AR89



ENERGY TRUST

Enterra

2006
FINANCIAL REPORT

The following is Management's Discussion and Analysis ("MD&A") of Enterra Energy Trust ("the Trust" or "Enterra") for the year ended December 31, 2006. This MD&A should be read in conjunction with the consolidated financial statements, together with the accompanying notes, of the Trust for the year ended December 31, 2006. All amounts are stated in Canadian dollars and are prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") except where otherwise indicated. This MD&A was written as of March 23, 2007.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This MD&A includes forward-looking statements. All statements other than statements of historical facts contained in this MD&A, including statements regarding the Trust's future financial position, business strategy and plans and objectives of management for future operations, are forward-looking statements. The words "believe," "may," "will," "estimate," "continue," "anticipate," "intend," "should," "plan," "expect" and similar expressions, as they relate to the Trust, are intended to identify forward-looking statements. The Trust has based these forward-looking statements largely on the Trust's current expectations and projections about future events and financial trends that the Trust believes may affect its financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions as described elsewhere in this MD&A.

Other sections of this MD&A may include additional factors that could adversely affect the Trust's business and financial performance. Moreover, the Trust operates in a very competitive and rapidly changing environment. New risk factors emerge from time to time and it is not possible for management to predict all risk factors, nor can the Trust assess the impact of all factors on the Trust's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

The Trust undertakes no obligation, except as required by securities law, to update publicly or revise any forward-looking statements. You should not rely upon forward-looking statements as predictions of future events or performance. The Trust cannot assure you that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although the Trust believes that the expectations reflected in the forward-looking statements are reasonable, the Trust cannot guarantee future results, levels of activity, performance or achievements.

SPECIAL NOTE REGARDING NON-GAAP TERMS

This document contains the term "funds from operations", which is a non-GAAP term. The Trust uses this measure to help evaluate its performance. The Trust considers it a key measure for the ability of the Trust to repay debt, make distributions to unitholders and to fund future growth through capital investment. The term should not be considered as an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with Canadian GAAP as an indicator of the Trust's performance. Funds from operations, as determined by the Trust may not be comparable to that reported by other companies. The reconciliation for funds from operations to cash provided by operating activities can be found in the non-GAAP financial measures section of this MD&A.

CERTAIN FINANCIAL REPORTING MEASURES

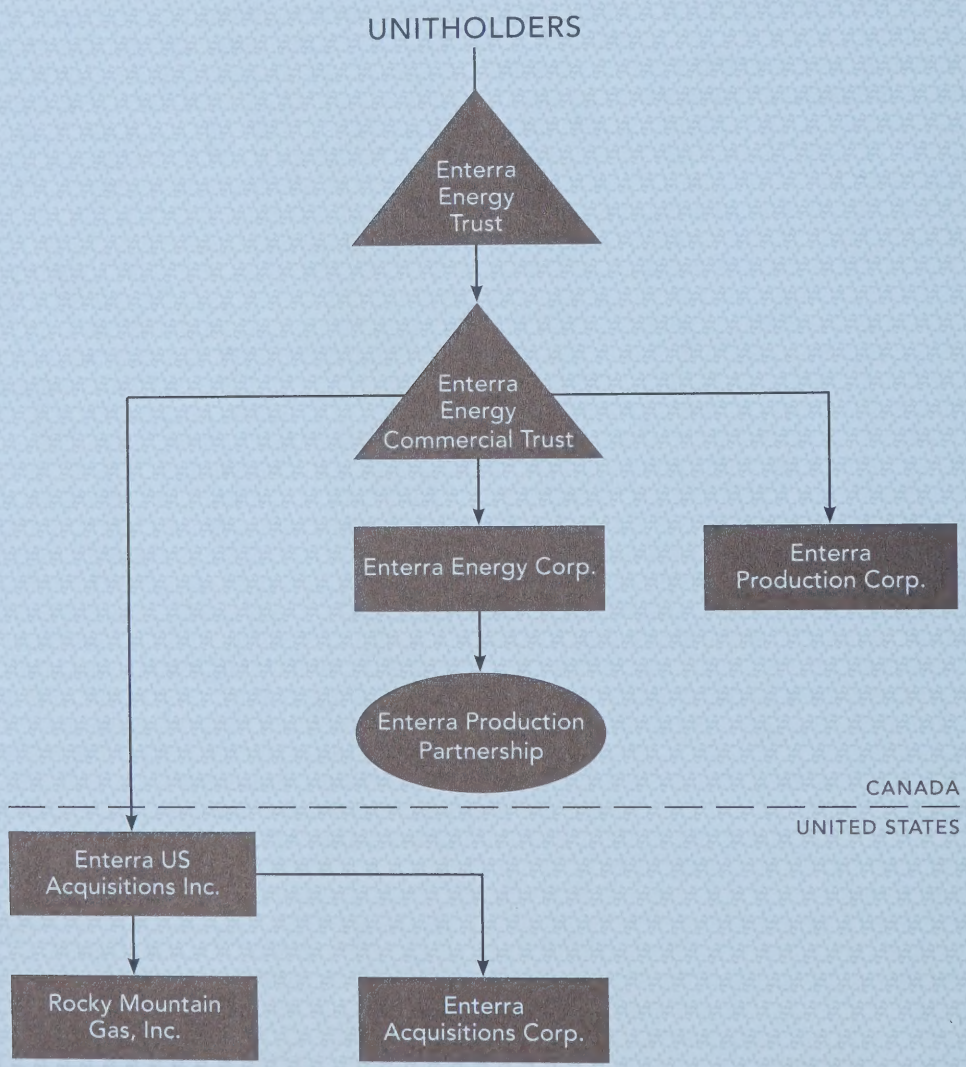
Natural gas volumes recorded in thousand cubic feet ("mcf") are converted to barrels of oil equivalent ("boe") using the ratio of six (6) thousand cubic feet to one (1) barrel of oil ("bbl"). Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead.

OVERVIEW AND STRATEGY

Enterra is a Canadian oil and gas trust with trust units listed on the Toronto Stock Exchange (ENT.UN) and the New York Stock Exchange (ENT). The Trust's head office is located in Calgary, Alberta and its United States office is located in Carney, Oklahoma.

The Trust's portfolio of crude oil, natural gas liquids and natural gas interests is geographically diversified and is balanced between natural gas and liquids production. The Trust's properties are located principally in Alberta, British Columbia and Oklahoma with average production for 2006 of 12,352 boe/day, which was comprised of approximately 59% natural gas and 41% crude oil and natural gas liquids.

In July 2006, the Trust announced that it would strive to make monthly cash distributions to its unitholders based on a target payout ratio range of 60% to 70% of funds from operations. The Trust's distributions in 2006 were approximately 105% of funds from operations, exceeding that target payout range, in part due to a higher level of distributions paid in the first seven months of 2006 and in part due to a lower commodity price environment during the later part of the year. Adjusting for the



All of the entities shown above that are below "Enterra Energy Trust" are, direct or indirect, wholly-owned subsidiaries of the Trust.

higher level of distributions paid in the first seven months of 2006 compared to those paid in August to December, the payout ratio would have been 82%. While the Trust believes it is important to deliver sustainable and predictable distributions to its unitholders, all future distributions will be determined by the board of directors ("Board") of Enterra Energy Corp., as administrator of the Trust, based on the circumstances as they exist at that time and will be subject to a number of factors, many of which are beyond the Trust's control. These factors include unforeseen events which impact the Trust's production levels, the prices received for that production and the cost structure associated with the Trust's operations. The Trust will continue to monitor its payout ratio to ensure that over the medium and long term, the ratio remains in the target range.

Enterra is structured as a trust rather than a corporation to provide a more tax-efficient means to distribute funds to its unitholders under current Canadian tax laws. On October 31, 2006 the Canadian Minister of Finance announced certain proposed changes to the taxation of publicly traded trusts (see "Implications of Recent Tax Proposals by Canadian Minister of Finance" below). If enacted, the changes will result in the Trust being subject to taxation in a manner similar to corporations.

ENTERRA'S GOAL, BUSINESS STRATEGY AND OPERATING PRINCIPLES

Enterra's goal is to generate returns for its unitholders through a combination of cash distributions that are predictable, sustainable and increase over time, and capital appreciation from steady and consistent increases in reserves, production and funds from operations per trust unit. To achieve that goal the Trust has adopted a three-pronged strategy as follows.

Organic Growth

The Trust currently targets a distribution level of 60% to 70% of funds from operations to unitholders and to invest the balance in the development of the large portfolio of lower-risk opportunities it has identified within its existing asset base. The individual nature and number of the opportunities varies across the Trust's properties, but in aggregate the Trust believes they offer a means of adding reserves and production on a basis that will be accretive to unitholders and at a pace that generally is within the Trust's control. As a result, the Trust believes that investing in such projects is in the long-term interest of unitholders.

Accretive Acquisitions

Corporate and property acquisitions are an effective means of consolidating assets, improving efficiencies in existing core areas or adding new core areas. The Trust intends to be pro-active, focused and disciplined in its approach to such acquisitions. Generally, the Trust seeks to make acquisitions that:

- are accretive to funds from operations per trust unit and accretive to at least one of reserves or production per trust unit;
- add to the Trust's portfolio of infill and step-out drilling opportunities, which the Trust believes to be lower-risk in nature;
- consolidate the Trust's position within an existing core area or create a new core area;
- leverage the Trust's existing expertise;
- have high working interests and operatorship; and
- maintain a reasonable balance among oil and natural gas production, and geographic diversification.

Strategic Partnerships

The Trust actively seeks to align itself with industry partners that provide access to projects that otherwise may not be available due to the nature or degree of risk involved or due to the expertise required to properly capitalize on the opportunity. The basis of the partnerships will vary, but may involve a farmout of existing assets or a joint acquisition with a partner followed by a farmout or joint venture. The Trust's objectives in structuring these relationships include:

- providing controlled exposure to higher-risk, higher-return opportunities;
- aligning with management teams or individuals with specific experience, proven skills or a demonstrated competitive advantage;
- adding reserves and production over an extended period of time at minimal cost and risk to Enterra and, as a result, providing a source of funds for future distributions; and

- creating opportunities to purchase at an attractive cost, assets from a partner once the risk is better defined or once the necessary expertise to exploit the opportunity has been acquired by the Trust.

In pursuing the Trust's growth strategies Enterra seeks to manage the risk to unitholders by following a number of operating principles. These principles are intended to maximize flexibility and ability to capitalize on opportunities, while reducing the volatility and increasing the predictability of distributions. These operating principles include:

- diversifying the source of production geographically so that Enterra is less dependent on one market for production or one area for future development;
- maintaining a reasonable balance among crude oil production, natural gas liquids production and natural gas production, so that Enterra is less vulnerable to short term price fluctuations for any single commodity;
- seeking high working interests, operatorship, and ownership of associated infrastructure, so that the Trust is better able to control the pace and timing of capital expenditures;
- maintaining a multi-year inventory of lower-risk development projects, so that the Trust is able to support its strategy of reinvesting in organic growth opportunities;
- moving towards a conservative balance sheet with a target ratio of total net debt (defined as bank indebtedness less current assets plus current liabilities) to funds from operations of 1:1, so that Enterra is positioned to capitalize on acquisition opportunities when they arise; and
- hedging up to 50% of projected gross production up to 24 months in advance using price collars and avoiding fixed price sales, so that the Trust is less exposed to significant short-term swings in commodity prices, but has protected a base level of distributions and preserved a degree of upside.

ACQUISITION HIGHLIGHT

During the first six months of 2006, the Trust completed the acquisition of oil and natural gas producing assets located in Oklahoma ("Oklahoma Assets"). The acquisition was completed in four tranches. Volumes for each closing were based on production deliverability. The first closing occurred on January 18, 2006 and represented approximately 1,300 boe/day of deliverability. The second closing occurred on March 21, 2006 and represented approximately 3,700 boe/day of deliverability. The final two closings occurred on April 4, 2006 and April 18, 2006 and represented in total approximately 1,300 boe/day of deliverability. In the four week period following the fourth closing, production volumes were 5,703 boe/day. The aggregate net purchase price of $307.6 million was paid for through the issuance of 5,685,028 trust units valued at $116.5 million, cash of $181.0 million, including $8.9 million that remains unpaid at December 31, 2006, and closing costs of $10.0 million.

IMPLICATIONS OF RECENT TAX PROPOSALS BY THE CANADIAN MINISTER OF FINANCE

On October 31, 2006 the Canadian Minister of Finance (the "Finance Minister") announced a proposal to apply a tax at the trust level on distributions of certain income from publicly-traded mutual fund trusts and other "specified investment flow-through" ("SIFT") entities at rates of tax comparable to the combined federal and provincial corporate tax and to treat such distributions as dividends to the unitholders. The Finance Minister said existing trusts would have a four-year transition period and would not be subject to the new rules until 2011. However, the proposals also provide that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being "revisited", presumably with the loss of the benefit to the Trust of that transition period. As a result, the adverse tax consequences resulting from the proposals could be realized sooner than 2011. On December 15, 2006 the Finance Minister provided additional guidance clarifying what will be deemed to be "normal growth". Specifically, the transition period will not be revisited for any SIFT whose equity capital grows as a result of issuances of new equity, in any certain intervening periods,

by an amount that does not exceed the greater of $50 million and an objective "safe harbour" amount. The safe harbour amount will be measured by reference to a SIFT's market capitalization as of the end of trading on October 31, 2006 by measuring the value of the SIFT's issued and outstanding publicly-traded units and excluding options or other interests that were convertible into units of the SIFT. For the period from November 1, 2006 to the end of 2007, a SIFT's safe harbour will be 40% of that October 31, 2007 benchmark. Thereafter, for each calendar year 2008 through 2010 the safe harbour will be 20% of that benchmark. The annual safe harbour limits are cumulative but the $50 million amounts are not. New equity for purposes of the safe harbour will include issuances of units and debt that is convertible into units, but will not include new equity raised to replace debt that was outstanding as of October 31, 2006, or units acquired through a right existing as of October 31, 2006.

As of October 31, 2006 the Trust had a benchmark market capitalization of approximately $408 million. As a result, assuming the proposals are enacted as proposed, the safe harbour limit for the Trust from November 1, 2006 to the end of 2007 is 40% of the benchmark or approximately $163 million, and 20% of the benchmark or approximately $82 million for each calendar year 2008 through 2010. On November 21, 2006 the Trust issued trust units and debentures for total gross proceeds of $178.3 million. The net proceeds of the issue combined with drawings under the Trust's Syndicated Credit Facilities were used to repay in full bridge loans that had been outstanding at October 31, 2006. As a result, it does not appear that the issuances will be considered new equity for purposes of the safe harbour amounts.

If the proposals are ultimately enacted, the implementation of such proposals is expected to result in adverse tax consequences to the Trust and certain of its unitholders (including most particularly investors that are tax exempt or non-residents of Canada) which could be material and may impact cash distributions from the Trust and the value of its units. In the absence of legislation implementing the proposals, the implications of the proposals are difficult to evaluate and no assurance can be provided as to the extent and timing of their application to Enterra. The Trust continues to research its position based on the proposed rules and is waiting for the final legislation.

OVERALL PERFORMANCE

Increased natural gas sales volumes, resulting from the acquisition of High Point Resources Inc. ("High Point") effective August 17, 2005 and the inclusion of the acquisition of the Oklahoma Assets as of their respective closing dates during Q1 and Q2 2006, positively impacted the Trust's 2006 operating and financial results.

Average production increased by 60% to 12,352 boe/day in 2006 from 7,741 boe/day in 2005. The Trust exited the year with sales volumes of approximately 12,442 boe/day, 34% higher than the 2005 exit rate of 9,282 boe/day.

The positive impact of the year-over-year increase in production volumes was partially offset by a number of factors including lower natural gas prices, and higher G&A and interest expenses. Cash G&A expenses increased by 12% in 2006 to an average of $3.80/boe from $3.40/boe in 2005. Interest expenses were also up significantly, reflecting the high cost of the bridge loan facilities arranged to finance the purchase of the Oklahoma Assets, rising 467% to $26.7 million in 2006 compared to $4.7 million the prior year. As a result, funds from operations increased by 22% to $86.1 million in 2006 from $70.5 million in 2005.

Proved and probable reserves increased by 44% from the end of 2005 to the end of 2006 largely reflecting the acquisition of the Oklahoma Assets during the first half of 2006. However, higher forecast operating costs, lower forecast commodity prices and to a lesser extent poorer than expected new well performance resulted in downward revision of earlier reserve estimates in both Canada and U.S. As a result, an after-tax write-down of $44.5 million in the carrying value of property plant and equipment was necessary. The write-down represents a significant portion of the net loss for the year of $64.2 million compared to net earnings of $1.0 million in 2005. On a per unit basis, the Trust realized a net loss of $1.46/unit compared to net earnings of $0.03/unit in 2005.

Over the course of 2006, the Trust distributed a total of $90.5 million to unitholders or an average of US$1.86/unit, representing increases of 37% and nil% respectively compared to total distributions of $66.2 million and average distributions of US$1.86/unit in 2005.

SUMMARIZED FINANCIAL AND OPERATIONAL DATA
(in thousands except for volumes and per unit amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	Change	2006	2005	Change
Revenues	$ 56,043	$ 50,602	11%	$ 244,408	$ 158,097	55%
Average sales (boe/day)	11,905	9,883	20%	12,352	7,741	60%
Exit sales rate (boe/day)	12,442	9,282	34%	12,442	9,282	34%
Cash provided by operating activities	$ 26,163	$ 19,575	34%	$ 64,485	$ 68,120	(5%)
Funds from operations[1]	$ 9,558	$ 19,519	(51%)	$ 86,117	$ 70,545	22%
Net earnings (loss)	$ (69,189)	$ (12,937)	435%	$ (64,239)	$ 970	(6,723%)
Net earnings (loss) per unit - basic	$ (1.40)	$ (0.37)	278%	$ (1.46)	$ 0.03	(4,967%)
Weighted average number of units outstanding – basic	49,415	35,358	40%	44,142	29,534	49%
Average price per barrel of oil	$ 55.64	$ 56.83	(2%)	$ 62.13	$ 58.47	6%
Average price per mcf of natural gas	$ 7.91	$ 8.82	(10%)	$ 7.53	$ 8.40	(10%)
Production expenses per boe	$ 16.04	$ 12.26	31%	$ 11.17	$ 11.55	(3%)

[1] Funds from operations is a non-GAAP financial measure. See non-GAAP financial measures section of the MD&A for a reconciliation of this measure.

SELECT FINANCIAL INFORMATION
(in thousands except per unit amounts)

	2006	2005	2004
Revenues	$ 244,408	$ 158,097	$ 108,293
Net earnings (loss)	$ (64,239)	$ 970	$ 14,027
Net earnings (loss) per unit			
Basic	$ (1.46)	$ 0.03	$ 0.62
Diluted	$ (1.46)	$ 0.03	$ 0.62
Total assets	$ 795,366	$ 611,543	$ 221,128
Total long term liabilities	$ 147,761	$ 126,322	$ 39,544
Distributions declared	$ 90,698	$ 69,496	$ 42,361
Distributions declared per unit (US$)	$ 1.80	$ 1.90	$ 1.66

QUARTERLY FINANCIAL INFORMATION

QUARTERLY FINANCIAL INFORMATION
(in thousands except for per unit amounts)

	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues	$ 56,043	$ 73,335	$ 67,313	$ 47,717	$ 50,602	$ 47,638	$ 29,807	$ 30,050
Earnings (loss) before taxes and non-controlling interest	(101,242)	$ (6,879)	$(10,579)	$ (3,149)	$(28,526)	$ 7,530	$ 947	$ 3,757
Net earnings (loss)	(69,189)	$ 3,000	$ (296)	$ 2,248	$(12,937)	$ 7,089	$ 2,567	$ 4,251
Net earnings (loss) per unit								
Basic	$ (1.40)	$ 0.07	$ (0.01)	$ 0.06	$ (0.37)	$ 0.23	$ 0.10	$ 0.16
Diluted	$ (1.40)	$ 0.07	$ (0.01)	$ 0.06	$ (0.37)	$ 0.23	$ 0.10	$ 0.16
Distributions declared per unit (US$)	$ 0.36	$ 0.36	$ 0.54	$ 0.54	$ 0.52	$ 0.49	$ 0.46	$ 0.43

Over the last 8 quarters, the Trust has realized a steady growth of revenues. This growth fell off slightly in Q4 2006 due to a combination of lower volumes and lower prices compared to the previous quarter. While distributions grew steadily over the early quarters, they dropped in Q3 and Q4 2006 along with the Trust's 2006 strategy to pursue organic growth.

RESULTS OF OPERATIONS

The Trust's average production for 2006 increased by 60% to 12,352 boe/day from 7,741 boe/day in 2005. The increase largely reflects the acquisition of High Point in August 2005, the subsequent development of the properties, and the purchase of the Oklahoma Assets in Q1 and Q2 2006. The Trust's average production during 2006 consisted of 5,126 bbls/day of oil and natural gas liquids ("NGL") and 43,358 mcf/day of natural gas, resulting in a mix of 41% oil and NGL and 59% natural gas. As at December 31, 2006, the Trust had an exit rate of 12,442 boe/day.

Production for the fourth quarter of 2006 was also positively impacted by the acquisitions. Volumes for the period averaged 11,905 boe/day up 20% compared to the average for Q4 2005 of 9,883 boe/day, but 9% below the average for Q3 2006 of 13,070 boe/day. Factors contributing to the reduction in Q4 versus Q3 included normal production declines, operational problems in the Desan area of North Eastern British Columbia, production declines related to increased water production in the Clair area of North Western Alberta, and operational problems in Oklahoma. The impact of the problems was mitigated by the startup late in Q4 of a deep gas well in the Ricinus area of Alberta and by some success in addressing the operational problems at Desan and in Oklahoma. Production at the end of Q4 2006 was 5% above the average for the quarter at 12,442 boe/day.

In total in 2006, the Trust participated in the drilling of 45 (13.1 net) development wells; 28 (5.8 net) in Canada and 17 (7.3 net) in Oklahoma. In addition, 20 (10.0 net) wells were drilled on lands that are prospective for coal bed methane owned by the Trust in Wyoming. 18 (4.3 net) of the wells in Canada and 12 (3.0 net) of the wells in Oklahoma were initiated and operated by our strategic partners under area farmout agreements that resulted in our partners paying 100% of the cost in exchange for 70% of the Trust's working interest. Overall, the drilling in Canada and Oklahoma resulted in 34 (10.1 net) gas wells, 9 (1.5 net) oil wells, 2 (1.5 net) salt water disposal wells and an overall success rate of 100%.

Canadian Operations

Production in Canada for the year was relatively unchanged compared to 2005. Volumes averaged 2% higher at 7,578 boe/day in 2006 compared to 7,398 boe/day in 2005. However, the mix between commodities was more balanced reflecting the inclusion of High Point for the full year and the Trust's strategy of maintaining a reasonable balance among crude oil, natural gas liquids and natural gas production. Gas represented approximately 40% of total production in 2006 versus 25% in 2005.

Q4 2006 production in Canada was negatively impacted by operational issues at Desan and above normal production declines at Clair. Overall, volumes were down by 11% to 6,990 boe/day compared to the average for Q3 2006 of 7,491 boe/day and 24% lower than the average of 9,226 boe/day in Q4 2005. At Clair, an increase in the ratio of water to oil produced resulted in a drop in production of approximately 140 boe/day in Q4 versus Q3. At Desan, production from several wells was reduced during the quarter due to minor and expected water production. As a result, volumes from the area in Q4 were approximately 180 boe/day lower than in Q3. Remedial work to address the issue was undertaken in early 2007 and the production restored. Mitigating the impact of lower production at Clair and Desan was the startup of a deep gas well at Ricinus during November. The well has had a number of operational problems and has produced intermittently since it was completed in April 2006. Most of those issues have now been addressed enabling the well to contribute average production during the quarter of approximately 300 boe/day. The 24% drop in Q4 2006 production compared to Q4 2005 is largely attributable to natural production declines and to several small assets dispositions that totaled approximately 250 boe/day. The 2006 exit rate for Canada was 7,287 boe/day.

Of the 28 (5.8 net) wells that were drilled in Canada during 2006, 17 (4.3 net) were drilled under the Trust's farmout to JED Oil Inc. ("JED") whereby the JED paid 100% of the cost of the wells for a 70% interest. Overall, including the wells not initiated by JED, the drilling resulted in 19 (4.3 net) gas wells and 9 (1.5 net) oil wells.

U.S. Operations

Production in the United States averaged a total of 4,774 boe/day during 2006, of which 86% was natural gas and approximately 95% was attributable to the Oklahoma Assets that were acquired during Q1 and early Q2 2006.

Q4 2006 production levels were below expectation, averaging 4,915 boe/day or 12% less than the average for Q3 2006. The reduction in volumes reflected operational problems experienced in several project areas, including downtime due to pump failures and deferred well workovers. However, many of the problems were successfully addressed during the quarter which was reflected in the exit rate of 5,155 boe/day.

In total, the Trust participated in the drilling of 37 (17.3 net) wells in the U.S. in 2006. Of those, 17 (7.3 net) were in Oklahoma and 20 (10 net) were wells to test the economic viability of a coal bed methane project in Wyoming. Two (1.5 net) of the wells drilled in Oklahoma were salt water disposal wells drilled by the Trust in support of the on-going development drilling program of its strategic partner, Petroflow Energy Inc. ("Petroflow"). While the total cost of the Trust's share of the wells was paid by the Trust, ultimately 100% of the amount plus interest will be recovered from Petroflow over a three-year period. To the end of 2006, Petroflow had drilled 12 gas wells, including five during Q4. Seven of the 12 wells were on production at the end of 2006. All of the wells drilled in the U.S. by or on behalf of the Trust during the year were successful.

PRODUCTION
(in thousands except for volumes and percentages)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
Daily Sales Volumes – Average						
Oil & NGL (bbls/day)	4,774	5,762	(17%)	5,126	5,453	(6%)
Natural gas (mcf/day)	42,788	24,727	73%	43,358	13,729	216%
Total (boe/day)	11,905	9,883	21%	12,352	7,741	60%
Daily Sales Volumes - Exit Rate						
Oil & NGL (bbls/day)	4,758	5,476	(13%)	4,758	5,476	(13%)
Natural gas (mcf/day)	46,105	22,836	102%	46,105	22,836	102%
Total (boe/day)	12,442	9,282	34%	12,442	9,282	34%
Sales Volumes mix by product						
Oil & NGL	40%	58%		41%	70%	
Natural gas	60%	42%		59%	30%	
	100%	100%		100%	100%	

PRODUCTION BY GEOGRAPHIC AREA
(in thousands except for volumes and percentages)

	Three Months Ended December 31, 2006		Year Ended December 31, 2006	
	Canada	U.S.	Canada	U.S
Daily Sales Volumes – Average				
Oil & NGL (bbls/day)	4,064	710	4,511	614
Natural gas (mcf/day)	17,556	25,232	18,401	24,956
Total (boe/day)	6,990	4,915	7,578	4,774
Daily Sales Volumes - Exit Rate				
Oil & NGL (bbls/day)	4,008	750	4,008	750
Natural gas (mcf/day)	19,676	26,429	19,676	26,429
Total (boe/day)	7,287	5,155	7,287	5,155
Sales Volumes mix by product				
Oil & NGL	58%	14%	60%	13%
Natural gas	42%	86%	40%	87%
	100%	100%	100%	100%

COMMODITY PRICING

West Texas Intermediate ("WTI") is a standard benchmark for the price of oil. WTI is expressed in US dollars per barrel ("bbl"). The Trust reports the price it receives for oil in Canadian dollars per bbl. Alberta Spot prices, represented as AECO hub pricing ("AECO"), is a standard benchmark for the price of natural gas in Western Canada. AECO prices are quoted in Canadian dollars per gigajoule ("GJ"). New York Mercantile Exchange ("Nymex") is a standard benchmark for the price of natural gas in the United States. Nymex prices are expressed in US dollars per million British Thermal Units ("mmbtu"). To simplify comparison, both an mmbtu and a GJ are approximately equal to a mcf of gas.

Natural gas prices on the Nymex decreased by US$1.30/mmbtu or 15%, from 2005, averaging US$7.26/mmbtu in 2006. In Canada, AECO pricing was down $2.20/GJ, or 25%, from 2005 levels, averaging $6.53/GJ. Reasons why Alberta spot prices decreased by more than NYMEX prices include the continued appreciation of the Canadian dollar against the US dollar and widening basis differentials attributable to soft natural gas storage demand.

In the fourth quarter, prices on the NYMEX were down significantly from the fourth quarter of 2005. Prices averaged US$6.62/mmbtu in Q4 2006 compared to US$12.85/mmbtu in Q4 2005. AECO pricing was down by 39% to $6.91/GJ compared to $11.39/GJ in Q4 2005. The decreases in gas prices over the prior year periods reflect the exceptionally high market prices realized during the later part of 2005 due to the unusually large number of hurricanes that adversely impacted onshore and offshore gas production in the Southern U.S.

World oil prices increased significantly in 2006 compared to 2005 reaching a high in July for WTI of US$74.47/bbl. Overall in 2006 WTI averaged US$66.22/bbl, up 17% from US$56.56/bbl in 2005. However, the potential benefit to the Trust of the price increase was mitigated by the strengthening of the Canadian dollar which rose from an average of $0.83 against the US dollar in 2005 to an average of $0.88 in 2006. In Q4 2006 WTI decreased 2% to US$68.64/bbl compared to US$70.24/bbl in Q4 of 2005.

Similar to the benchmark prices for both oil and gas, the average price received by the Trust for oil was up and for gas was down in 2006 compared to 2005. The Trust's average oil price increased by 7% in 2006 to an average of $62.13/bbl from $58.11/bbl in 2005. The average gas price decreased by 10% in 2006 to an average of $7.53/mcf compared to $8.40/mcf in 2005.

PRICING
(in thousands except for volumes and pricing)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
Pricing Benchmarks						
WTI (US$/bbl)	60.21	60.03	–	66.22	56.56	17%
Average exchange rate: US$1.00 to Cdn$	1.14	1.17	(3%)	1.13	1.21	(7%)
WTI (Cdn$/bbl)	68.64	70.24	(2%)	74.83	68.44	9%
AECO monthly index (Cdn$/GJ)	6.91	11.39	(39%)	6.53	8.73	(25%)
Nymex (US$/mmbtu)	6.62	12.85	(48%)	7.26	8.56	(15%)
Average Prices Received by the Trust						
Oil (Cdn$ per bbl)	55.64	56.83	(2%)	62.54	58.11	8%
Natural gas (Cdn$ per mcf)	7.12	8.82	(19%)	6.70	8.40	(20%)
Oil hedging settlements (Cdn$ per bbl)	–	–	–	(0.41)	–	–
Natural gas hedging settlements (Cdn$ per mcf)	0.79	–	–	0.83	–	–
Combined Oil (Cdn$ per bbl)	55.64	56.83	(2%)	62.13	58.11	7%
Combined Natural gas (Cdn$ per mcf)	7.91	8.82	(1%)	7.53	8.40	(10%)
Total[(1)] (Cdn$ per boe)	50.48	55.26	(9%)	51.82	55.83	(7%)

(1) Includes NGL

The Trust has a policy of hedging up to 50% of projected gross production up to 24 months in advance using price collars and avoiding fixed price sales so that the Trust is less exposed to significant short-term swings in commodity prices. Gains from the risk management program resulted in added gas revenues of $13.1 million in 2006, including $1.7 million realized during Q4 2006. Those gains resulted in approximately an 11% increase in the average gas price received by the Trust in 2006 and a 12% increase in Q4 2006, as compared to the price the Trust would have received before hedging. The profits from the gas price hedges were offset by slight losses on oil price hedges totaling $0.7 million for the year or approximately $0.41 per bbl.

At December 31, 2006, the Trust had the following financial derivatives and fixed price contracts outstanding:

DERIVATIVE INSTRUMENT	COMMODITY	PRICE	VOLUME (PER DAY)	PERIOD
Collars	Gas	7.50 by 12.00 (Cdn$/GJ)	7,500 GJ	January 1, 2007 – March 31, 2007
Fixed	Gas	7.80 (Cdn$/GJ)	2,500 GJ	January 1, 2007 – March 31, 2007
Collars	Gas	7.50 by 9.00 (Cdn$/GJ)	10,000 GJ	April 1, 2007 – October 31, 2007
Collars	Gas	8.00 by 12.00 (Cdn$/GJ)	10,000 GJ	November 1, 2007 – March 31, 2008
Collars	Gas	8.00 by 15.70 (US$/mmbtu)	12,000 mmbtu	January 1, 2007 – March 31, 2007
Collars	Gas	7.50 by 11.20 (US$/mmbtu)	5,000 mmbtu	April 1, 2007 – October 31, 2007
Collars	Gas	7.50 by 11.10 (US$/mmbtu)	5,000 mmbtu	April 1, 2007 – October 31, 2007
Collars	Gas	8.00 by 16.40 (US$/mmbtu)	10,000 mmbtu	November 1, 2007 – March 31, 2008
Collars	Oil	55.00 by 81.20 (US$/bbl)	1,000 bbl	January 1, 2007 – June 30, 2007
Collars	Oil	55.00 by 80.50 (US$/bbl)	1,000 bbl	January 1, 2007 – December 31, 2007
Collars	Oil	55.00 by 80.50 (US$/bbl)	1,000 bbl	July 1, 2007 – December 31, 2007
Collars	Oil	55.00 by 78.60 (US$/bbl)	500 bbl	January 1, 2007 – December 31, 2007
Fixed purchase physical	Power (Alberta)	62.90 (Cdn$/Mwh)	72 Mwh	January 1, 2007 – December 31, 2009

Consistent with the Trust's price risk mitigation strategy, these hedging positions represent approximately 47% of the Trust's expected production before royalties on a boe/day basis for fiscal 2007.

As at December 31, 2006 the financial instruments above had a mark-to-market value of $10.8 million which was recorded as a component of revenue in the consolidated financial statements.

Subsequent to December 31, 2006 the Trust entered into the following additional transactions:

- the Trust purchased US$11.20/mmbtu Nymex call options for 5,000 mmbtu/day for the April 1, 2007 to October 31, 2007 period to eliminate the ceiling on the $7.50 by $11.20 gas collar noted in the table above;
- the Trust sold 5,000 mmbtu/day, under fixed price Nymex contracts at US$7.555/mmbtu beginning April 1, 2007 to October 31, 2007; and
- the Trust entered into a costless collar covering 500 bbl/day of production for the period beginning January 1, 2008 to June 30, 2008 with a ceiling of US$75.25/bbl and a floor of US$55.00/bbl.

REVENUES

The positive impact on year-over-year revenues of the over two-fold increase in natural gas sales volumes in 2006 compared to 2005 was partially offset by the 10% decrease in the sales price of natural gas. For oil and NGL, revenues were relatively unchanged as the 6% decrease in volumes was largely offset by a 5% increase in the average price received by the Trust. Overall, in 2006 revenues increased by $86.3 million or 55% compared to 2005, with much of the increase attributable to the acquisition of the Oklahoma Assets during Q1 and early in Q2.

REVENUES
(in thousands)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
Revenues						
Oil and NGL	$ 24,140	$ 30,105	(20%)	$ 114,481	$ 115,645	(1%)
Natural gas	31,156	20,143	55%	119,111	42,098	183%
Unrealized mark to market gains on oil and natural gas financial instruments	559	354	57%	10,628	354	2,902%
Other	188	–	–	188	–	–
Total	$ 56,043	$ 50,602	11%	$ 244,408	$ 158,097	55%

REVENUES BY GEOGRAPHIC AREA
(in thousands)

	Three Months Ended December 31, 2006		Year Ended December 31, 2006	
	Canada	U.S.	Canada	U.S.
Revenues				
Oil and NGL	$ 19,642	$ 4,498	$ 97,690	$ 16,791
Natural gas	13,072	18,084	54,564	64,547
Unrealized mark to market gains (loss) on oil and natural gas financial instruments	(1,286)	1,845	4,664	5,964
Other	(59)	247	(59)	247
Total	$ 31,369	$ 24,674	$ 156,859	$ 87,549

Revenue in Q4 2006 increased 11% to $56.0 million from $50.6 million in 2005. Similar to the full year results, the increase in revenue was largely attributable to a 73% increase in natural gas volumes largely attributable to the acquisition of the Oklahoma Assets, tempered by a 9% drop in the overall price per boe received by the Trust and lower production in Canada.

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties and wellhead taxes, less Alberta Royalty Tax Credits ("ARTC"), increased in 2006 compared to 2005 as a result of increased revenue in the period. Royalties vary depending on the total volumes sold and the price received by the Trust for the sales.

Q4's overall royalty rate was significantly lower in 2006 as compared to 2005. The difference is largely attributable to approximately $3.0 million in realized hedging gains included in revenue which do not attract a royalty, a reduction in royalty rates for the Desan properties, and deep gas royalty credits granted to certain wells in the Ferrier area of West Central Alberta.

ROYALTIES
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
Royalties	$ 11,196	$ 12,920	(13%)	$ 48,288	$ 36,079	34%
As a percentage of oil, NGL and natural gas revenue	20%	26%		21%	23%	
Royalties per boe	$ 10.22	$ 14.21	(28%)	$ 10.71	$ 12.77	(16%)

ROYALTIES BY GEOGRAPHIC AREA
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31, 2006		Year Ended December 31, 2006	
	Canada	U.S.	Canada	U.S.
Royalties	$ 5,712	$ 5,484	$ 28,253	$ 20,035
As a percentage of oil, NGL and natural gas revenue	17%	24%	19%	25%
Royalties per boe	$ 8.88	$ 12.13	$ 10.21	$ 11.50

PRODUCTION EXPENSES

Despite an industry environment characterized by excessive demand for supplies and services, the Trust's average operating expense in 2006 fell by 3% to $11.17 per boe compared to $11.55 per boe the prior year in part reflecting the acquisition of the lower-cost Oklahoma Assets. Consistent with that decrease, while production volumes increased by 60% in 2006 compared to 2005, total operating expenses only increased by 54% to $50.4 million from $32.6 million in 2005.

In Q4 2006, total and per unit operating costs increased over Q4 2005 due to temporary operating problems within Oklahoma, work-over expenses in Canada and the timing of the realization of certain operating costs within 2006. These increased costs are amplified on a per boe basis by normal declines in Canada. As a result, operating costs in Q4 were higher than the prior year, averaging $16.04 per boe or $17.6 million in total compared to $12.11 per boe or $11.0 million in total in Q4 2005.

Canadian Assets

In Canada in 2006, the average operating expense increased by 13% to $12.84 per boe versus $11.38 per boe in 2005 due largely to inflationary cost pressures and to a lesser extent due to normal production declines. Total operating expenses increased at a slower pace, rising 16% in 2006 to $35.5 million from $30.7 million in 2005, reflecting the year-over-year decrease in production volumes.

Similar factors adversely impacted the average operating expense in Q4 2006 compared to the same period in 2005, and were further affected by the timing of certain 2006 operating costs that were realized in Q4 2006. While total operating costs in Q4 2006 increased by a relatively modest 24% to $12.4 million from $10.0 million in Q4 2005, the average operating cost jumped by 64% to $19.28 per boe in the last quarter of 2006 from $11.74 per boe the prior year due to a 24% period-over-period decline in production volumes.

U.S. Assets

Operating expenses for the U.S. Assets for 2006 averaged $8.52 per boe. For the Q4 2006, because of the deferred expenses, pump failures, electrical problems and pump sizing issues, the operating costs had increased to $11.43 per boe in comparison to $9.66 per boe for these assets during Q3.

Just prior to the acquisition of the Oklahoma Assets, the previous owners had begun a drilling program in a new project area. Early results of this program were very encouraging. As drilling continued into an area with less available data, start-up failures were experienced on many of the new wells. The cause of this was two fold; these new wells were drilled in an area where productivity had not been tested and the fluid production was not easily predictable so pump sizing was difficult and many wells required multiple pump changes in order to maximize production. Secondly, there were some cases of early equipment failures which were a result of some unusual electrical issues and start up failures. Hence, the inordinate number of workovers and repair operations that began during the third quarter and continued throughout the remainder of the year caused higher than expected operating costs. To compound the increase in repair frequency, the costs of goods and services increased over the year and that increase was not taken into account in our projections.

PRODUCTION EXPENSES
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
Production expenses	$ 17,570	$ 11,007	60%	$ 50,361	$ 32,620	54%
Production expenses per boe	$ 16.04	$ 12.11	32%	$ 11.17	$ 11.55	(3%)

PRODUCTION EXPENSES BY GEOGRAPHIC AREA
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31, 2006		Year Ended December 31, 2006	
	Canada	U.S.	Canada	U.S.
Production expenses	$ 12,399	$ 5,171	$ 35,513	$ 14,848
Production expenses per boe	$ 19.28	$ 11.43	$ 12.84	$ 8.52

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses ("G&A") increased by 97% to $20.4 million from $10.3 million in 2005. The change is largely due to the increased asset base of the Trust and the associated increased personnel and administrative functions, including the expansion into the U.S., together with the need to comply with increasing regulation, such as the Sarbanes-Oxley Act. G&A per boe increased by 23% to $4.52/boe in 2006 compared to $3.66/boe in 2005. Within G&A, the non-cash unit based compensation increased to $3.2 million in 2006 from $0.7 million in 2005. This non-cash unit based compensation includes expenses for both unit option plans and the recently implemented performance and restricted unit plans.

G&A expenses for Q4 2006 increased over the corresponding period in 2005 due to increased year end costs such as reserves analysis for the larger asset base, year end audit fees covering the expanded operations of the Trust, year end compensation for the larger employee base and expanded office space to accommodate the Trust's growth. For 2007, these costs are expected to have a smaller impact as they will be realized over the entire year as opposed to a single quarter.

GENERAL AND ADMINISTRATIVE EXPENSES
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
G&A expenses – cash	$ 7,079	$ 2,727	160%	$ 17,145	$ 9,600	79%
G&A expenses – non cash	529	263	101%	3,229	731	342%
Total G&A expenses	$ 7,608	$ 2,990	154%	$ 20,374	$ 10,331	97%
G&A per boe – cash	$ 6.47	$ 3.00	116%	$ 3.81	$ 3.40	12%
G&A per boe – non cash	$ 0.48	$ 0.29	66%	$ 0.71	$ 0.26	173%
Total G&A per boe	$ 6.95	$ 3.29	111%	$ 4.52	$ 3.66	23%

INTEREST EXPENSE

Interest expense increased in 2006 mainly due to the financing of the acquisition of the Oklahoma Assets. On March 21, 2006, the Trust entered into a $110.0 million bridge credit facility to replace its current operating facilities as well as a US$200.0 million bridge credit facility. These facilities were partially replaced on November 21, 2006 with the issuance of $138.0 million of 8% unsecured subordinated convertible debentures and $40.3 million of trust units. The remaining balance of bridge facilities was replaced with a $180.0 million extendible credit facility and a $20.0 million extendible operating credit facility.

Interest expense increased in Q4 2006 compared to Q4 2005 due to the bridge loan facilities that were outstanding until November 21, 2006, the higher average outstanding loan balances during the period and the interest on the convertible debentures that were issued during the fourth quarter of 2006.

The Trust expects interest expense to decrease significantly in 2007 due to the replacement of the bridge loan facilities in November 2006 with lower interest credit facilities, convertible debentures and equity.

INTEREST EXPENSE
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
Bank indebtedness, capital lease, and notes payable at end of period	$ 189,856	$ 102,101	86%	$ 189,856	$ 102,101	86%
Convertible debentures	78,974	–	–	78,974	–	–
Total convertible debentures, bank indebtedness, capital lease, and notes payable at end of period	$ 268,830	$ 102,101	163%	$ 268,830	$ 102,101	163%
Interest expense on bank indebtedness, capital lease, and notes payable	$ 7,739	$ 2,000	287%	$ 25,898	$ 4,715	449%
Interest expense on convertible debentures	819	–	–	819	–	–
Total interest expense	$ 8,558	$ 2,000	328%	$ 26,717	$ 4,715	467%
Interest expense per boe on bank indebtedness, capital lease, and notes payable	$ 7.07	$ 2.20	221%	$ 5.74	$ 1.67	244%
Interest expense per boe on convertible debentures	0.75	–	–	0.18	–	–
Total interest expense per boe	$ 7.81	$ 2.20	255%	$ 5.93	$ 1.67	255%

FINANCING FEES

Financing fees were incurred in 2006 related to the issuances and repayments of the bridge loan facilities, the issuance of equity, the issuance of convertible debentures and the new $200 million revolving credit facility. Of these fees, $5.4 million were related to the retirement of the bridge loan facilities and were expensed as incurred; $11.7 million were amortized into earnings as deferred financing fees on the various credit facilities and convertible debentures; $4.7 million of financing costs related to the convertible debentures and the $200 million revolving credit facility remained on the balance at December 31, 2006 as deferred financing costs; and $6.2 million were charged against unitholders' equity as unit issue costs.

DEPLETION, DEPRECIATION AND ACCRETION INCLUDING CEILING TEST IMPAIRMENTS ("DD&A")

The Trust recorded an impairment on its property, plant and equipment in 2006 totaling $66.0 million. Approximately 67% of this amount was due to a reduction in proven and probable reserves value due to a combination of forecast increased expenses, commodity prices and decreased reservoir performance (32%, 21% and 14% respectively). The remaining 33% was due to a reduction of the carrying value of undeveloped lands.

DD&A expense excluding the ceiling test impairment increased by 98% in 2006 compared to 2005, primarily due to the addition of the oil and natural gas properties acquired in the High Point and Oklahoma Asset acquisition. The DD&A expense per boe excluding the ceiling test impairment increased 24% in 2006 compared to 2005 due to the higher cost of reserves associated with the acquisitions.

In 2006 a provision of $17.2 million is included within DD&A due to a ceiling test write down in the United States cost center. Of this change, higher estimated future operating costs contribute to approximately 55% of the reduction and lower than expected performance of certain wells within the Oklahoma asset make up the remainder of the decrease in the net present value of the reserves to which the test is calculated.

In 2006 a provision of $48.8 million is included within DD&A due to a ceiling test write down in the Canada cost center. Of this provision approximately 45% is due to a reduction in the value of the reserves in the December 31, 2006 reserve report. The source of this decline in value is a reduction in forecast commodity prices (60% of reduction) and the remainder is due to increases in forecasted operating costs. Finally, a provision was required due to a lower amount and value of undeveloped lands in Canada resulting from lands given up in a swap of properties with JED and lower expectations for other undeveloped lands in the Trust's Canadian undeveloped lands.

In 2005 a provision of $13.8 million is included within DD&A due to a ceiling test write down in the United States cost center. The provision was required due to the expiration of certain undeveloped lands in Rocky Mountain Gas, Inc, which increased the cost base that the test is calculated on and a reduction of the reserves in the December 31, 2005 reserve report due to the results from the properties during 2005.

DEPLETION, DEPRECIATION AND ACCRETION
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
DD&A – excluding write down	$ 36,148	$ 27,812	30%	$ 135,429	$ 68,229	98%
Ceiling test provisions	66,019	13,844	377%	66,019	13,844	377%
DD&A	$ 102,167	$ 41,656	145%	$ 201,448	$ 82,073	145%
DD&A per boe – excluding impairment per boe	$ 33.00	$ 30.59	8%	$ 30.04	$ 24.15	24%
Ceiling test impairment per boe	60.28	15.23	296%	14.64	4.90	199%
DD&A per boe	$ 93.28	$ 45.82	104%	$ 44.68	$ 29.05	54%

In the fourth quarter of 2006, DD&A expense excluding the ceiling test impairment increased by 30% compared to 2005, due to the cost of the properties acquired with the Oklahoma Asset acquisition. The DD&A expense per boe excluding the ceiling test impairment increased 8% in the fourth quarter of 2006 compared to 2005 due to the higher cost of reserves associated with the acquisition.

GOODWILL IMPAIRMENT

In 2005, the Trust realized a $9.3 million impairment on the goodwill recorded in the United States reporting unit. In 2006, the Trust performed a goodwill impairment test and determined that goodwill was not impaired at December 31, 2006.

TAXES

The Trust is subject to tax on its income or loss for each taxation year, computed as though it was a separate individual resident in Canada. The taxation year of the Trust ends on December 31 of each year. Under the Trust Indenture, the Trust is not subject to income taxes if all of its taxable income will be paid or made payable by way of cash distributions to the unitholders.

The corporate subsidiaries of the Trust are subject to tax if deductions are inadequate to reduce taxable income to zero.

	Three Months Ended December 31,		Years Ended December 31,	
	2006	2005	2006	2005
Current tax expense	$ 643	$ 354	$ 1,324	$ 1,456
Future income tax (recovery)	(32,594)	(15,325)	(58,899)	(18,689)
Total tax (recovery)	$ (31,951)	$ (14,971)	$ (57,575)	$ (17,233)

Current tax expense relates to income taxes of $1.0 million resulting from the High Point group of assets for the taxation period ended August 17, 2005. The remainder of the $0.3 million relates to the underaccrual of capital taxes for the taxation years from 2003 to 2005.

Future income tax recovery of $58.9 million arises from several factors. The major factor is the decreased accounting basis of the property, plant and equipment stemming from the impairment of US cost center of $17.2 million, giving a future income tax recovery of $6.9 million, as well as the impairment of the Canadian cost center of $48.8 million giving a future tax recovery of $14.4 million. Depletion expense in Canada of $90.7 million accounts for another $27.2 million. The remainder of the decrease stems from an adjustment in the tax rate applied to temporary differences from 34% in 2005 to 30% in 2006 giving rise to an income tax recovery of $6.7 million.

On October 31, 2006 the Canadian Minister of Finance announced certain proposed changes to the taxation of publicly traded trusts (see "Implications of Recent Tax Proposals by Canadian Minister of Finance" above). If enacted, the changes will result in the Trust being subject to a tax in a manner similar to corporations effective January 1, 2011. The Trust continues to research its position based on the proposed rules and is waiting for the final legislation. As the tax proposals had not yet been substantially enacted as at December 31, 2006, the consolidated financial statements do not reflect the impact of proposed taxation.

NON-CONTROLLING INTEREST

The Trust's exchangeable shares are classified as non-controlling interest on the consolidated balance sheets. Income after tax attributable to these exchangeable shares is deducted from net earnings of the Trust on the consolidated statements of earnings.

In 2006, 1,661,047 exchangeable shares were exchanged into trust units (2005 – 953,129). The remainder of the exchangeable shares were converted into trust units by the end of January 2007.

NON-GAAP FINANCIAL MEASURES

The Trust provides financial measures in the MD&A that do not have a standardized meaning prescribed by GAAP. These non-GAAP financial measures may not be comparable to similar measures presented by other entities.

The purpose of these financial measures and their reconciliation to GAAP financial measures are shown below. All of the measures have been calculated consistent with previous disclosures by the Trust.

Funds from Operations

Management uses funds from operations to analyze operating performance and leverage. Funds from operations as presented is not intended to represent cash provided by operating activities nor should it be viewed as an alternative to net earnings or other measures of financial performance calculated in accordance with GAAP. All references to funds from operations throughout this MD&A are based on cash provided by operating activities before changes in non-cash working capital as reconciled in the table below:

	Three Months Ended December 31,		Years Ended December 31,	
	2006	2005	2006	2005
Cash provided by operating activities	$ 26,163	$ 20,575	$ 64,485	$ 68,120
Changes in non-cash working capital items	(16,605)	(1,056)	21,632	2,425
Funds from operations	$ 9,558	$ 19,519	$ 86,117	$ 70,545

In 2006, funds from operations increased by 22% over 2005. This increase is mainly due to the increased funds generated by the acquisition of the Oklahoma Assets, tempered by increased interest expense associated with the interim financing arrangements, comparably lower prices for natural gas and increased general and administrative costs.

In Q4 2006, the benefit of higher production volumes due to the acquisition of the Oklahoma Assets was more than offset by the effects of lower commodity prices, higher operating expenses, general and administrative costs and interest expense. As a result, funds from operations for the period declined by 51% to $9.6 million compared to $19.5 million in Q4 2005.

CASH DISTRIBUTIONS PAID TO UNITHOLDERS

The Trust pays monthly cash distributions in US dollars. Cash distributions are paid on the 15th of the following month (e.g. the December 2006 distribution was paid on January 15, 2007). These distributions are determined each month by the Board of Enterra Energy Corp., as administrator of the Trust, after review of a number of factors potentially impacting the Trust including its available prospects and opportunities, the outlook for commodity prices and other macro-economic factors, and the Trust's financial position and commitments.

On July 18, 2006, the Trust announced a change to its target payout ratio, reducing it from 90% to 100% of funds from operations to a range of 60% to 70%. The effect was a decrease in the monthly distribution to US$0.12 per unit compared to US$0.18 per unit in June 2006.

On January 19, 2007, due to significantly weaker commodity prices, capital market uncertainty resulting from the recent tax changes proposed by the Canadian government, and early conversion of debentures to trust units, the Trust decreased its monthly distribution to US$0.06 per unit from US$0.12.

The Trust continues to monitor the payout ratio to ensure that over the medium and long term, the ratio remains in the target range.

The monthly cash distributions per trust unit since the inception of the Trust are as follows:

US$	2007	2006	2005	2004	2003
January	$ 0.06	$ 0.18	$ 0.14	$ 0.10	
February	$ 0.06	$ 0.18	$ 0.14	$ 0.10	
March	$ 0.06	$ 0.18	$ 0.15	$ 0.11	
April		$ 0.18	$ 0.15	$ 0.11	
May		$ 0.18	$ 0.15	$ 0.11	
June		$ 0.18	$ 0.16	$ 0.12	
July		$ 0.12	$ 0.16	$ 0.12	
August		$ 0.12	$ 0.16	$ 0.12	
September		$ 0.12	$ 0.17	$ 0.13	
October		$ 0.12	$ 0.17	$ 0.13	
November		$ 0.12	$ 0.17	$ 0.13	
December		$ 0.12	$ 0.18	$ 0.14	$ 0.10

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
Cash distributions to unitholders	$ $19,574	$ 21,067	(7%)	$ 90,487	$ 66,195	37%
Funds from operations	$ 9,558	$ 19,519	(51%)	$ 86,117	$ 70,545	22%
Cash distributions as a percentage of funds from operations	205%	108%		105%	94%	

The payout ratio in 2006 was 105%, exceeding the target payout ratio of 60% to 70% of funds from operations, in part due to the higher level of distributions from January 2006 to July 2006 (June 2006 distribution of US$ 0.18 was paid in July 2006). In July 2006, the Trust reduced its monthly distribution, payable in August 2006, from US$0.18 per unit to US$0.12 per unit. Had the Trust paid a monthly distribution of US$0.12 for all of 2006 instead of the US$0.18 for January to August, the cash distributed to unitholders would have been $70.9 million, or 82% of funds from operations.

The payout ratio in Q4 2006 was 205%. In January 2007, the Trust reduced its monthly distribution, payable in February 2006, from US$0.12 per unit to US$0.06 per unit. Had the Trust paid a monthly distribution of US$0.06 per unit in Q4 2006 instead of US$0.12 per unit, the cash distributed to unitholders would have been $9.8 million, or 102% of funds from operations. While that level of distributions is above the target payout range of the Trust, as noted above, general and administrative costs and interest expense are considered to have been unusually high in the period and are expected to decrease in 2007.

To the extent that the Trust uses cash to finance acquisitions, development costs and other significant expenditures, the net cash that the Trust receives that is available for distribution to unitholders will be reduced. Hence, the timing and amount of capital expenditures may affect the amount of net cash flow received by the Trust and,

as a consequence, the amount of cash available to distribute to unitholders. Therefore, distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made with the use of available cash.

The Trust currently minimizes cash income taxes in corporate subsidiaries by maximizing deductions, however in future periods there may be cash income taxes if deductions in the corporate entities are not sufficient to eliminate taxable income. Taxability of the Trust is currently passed on to unitholders in the form of taxable distributions. If the proposed Trust taxation legislation is enacted, the Trust anticipates that the resulting tax commencing in 2011 at the Trust level would decrease cash flow and thus reduce cash distributions to unitholders.

The Board of Enterra Energy Corp., as administrator of the Trust has the discretion to determine the extent to which cash provided by operating activities will be allocated to the payment of debt service charges as well as the repayment of outstanding debt. As a consequence, the amount of cash retained to pay debt service charges or reduce debt will reduce the amount of cash available for distribution to unitholders during those periods in which funds are so retained.

For Canadian tax purposes, cash distributions are comprised of a return of capital portion, which is tax deferred, and return on capital portion, which is taxable income. The return of capital portion reduces the cost base of the trust units held. The cost base is required in the calculation of a capital gain or loss upon the disposition of the trust units. For 2006, the cash distributions declared for 2006 are approximately 80% return on capital (taxable) and 20% return of capital (tax deferred). For tax information for non-resident unitholders, please visit our website at www.enterraenergy.com.

CAPITAL EXPENDITURES

A component of the Trust's business strategy is to invest available funds not distributed to unitholders in lower-risk projects within core areas of its asset base. As well, the Trust continually seeks accretive acquisitions of oil and gas assets that will create new core areas with investment potential or will consolidate an existing core area. Any such purchases are financed with cash flows from operations, issuing new trust units or incurring new debt, or any combination thereof.

During the first and second quarters of 2006, the Trust acquired oil and natural gas properties located in Oklahoma. The Oklahoma Assets provide the Trust with a sizeable presence in the United States and a large portfolio of development drilling opportunities. The Trust acquired the assets in four stages.

Prior to closing the acquisition, the Trust acquired $49.7 million of notes payable by the primary vendors of the Oklahoma Assets. $11.2 million of these notes was assumed by the Trust as consideration on the closing of the first stage of the acquisition. The remaining notes were repaid, by the vendors, to the Trust upon the second closing of the acquisition. The acquisition of the notes, by the Trust, was financed with a US$50.0 million senior bridge credit facility.

On January 18, 2006, the Trust closed the first stage of the acquisition of the Oklahoma Assets. The results of the operations of the assets acquired are included in the Trust's consolidated financial statements as of January 18, 2006.

On March 21, 2006, the Trust closed the second stage of the acquisition of the Oklahoma Assets. Along with the second stage, the Trust acquired the operating company of the Oklahoma Assets. The results of operations of the assets acquired and the operating company are included in the Trust's consolidated financial statements as of March 21, 2006.

On April 4, 2006, the Trust closed the third stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 4, 2006.

On April 18, 2006, the Trust closed the fourth stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 18, 2006.

The total consideration paid for the acquisition was $307.6 million (5,685,028 units valued at $116.5 million and $181.0 million of cash, including $8.9 million that remained unpaid at December 31, 2006, and transaction costs of $10.0 million).

On September 28, 2006, the Trust closed a property swap agreement with JED whereby the Trust swapped certain of its interests in properties in the Ferrier area of Alberta, valued at $44.0 million for interests of JED in common with the Trust in East Central Alberta, the Desan area of North Eastern British Columbia and the Ricinus area of Alberta, valued at $30.9 million. The swap was based on independent third party engineering evaluations. The transaction also resulted in the termination of the Agreement of Business Principles between the Trust and JED whereby the Trust had a right of first refusal on properties that JED owned and JED had the ability to farm-in on the Trust's undeveloped lands. Concurrent with the swap, the Trust settled all amounts owing to JED.

The following table represents the Trust's capital expenditures that were paid for with cash. The source of this cash was through private placements of trust units and excess funds from the bridge financing. The table excludes certain capital expenditures, such as the portion of the Oklahoma Asset acquisition, which were paid for with non-cash consideration such as trust units.

CAPITAL EXPENDITURES PAID WITH CASH
(in thousands except for percentages)

	Three Months Ended December 31,			Years Ended December 31,		
	2006	2005	*Change*	2006	2005	*Change*
Capital expenditures	$ 5,144	$ 9,181	44%	$ 213,101	$ 33,617	534%

Capital additions, including non-cash additions, for the year ended December 31, 2006 were $420.0 million (2005 - $419.7 million). In addition to the acquisition of the Oklahoma Assets of $353.0 million (of which $8.9 million was unpaid at December 31, 2006), the assets acquired through the JED swap, including post closing adjustments, of $32.4 million, property, plant and equipment additions of $30.9 million, $3.3 million of net asset retirement obligations ("ARO") and $0.4 million related to minority interest accounting as per EIC-151 were charged to property, plant and equipment. Total dispositions for the year ended December 31, 2006 were $50.8 million (2005 - $nil).

The Trust accounts for its investment in its U.S. operations as a self sustaining operation, which means the capital assets associated with the U.S. operations (as well as all other balance sheet accounts for the U.S. operations) are subject to revaluation to the current exchange rate at each balance sheet date. The result of this revaluation is a change in the carrying value of the U.S. assets, which is not a result of capital additions or disposals.

In 2006, the Trust participated in the drilling of 45 (13.9 net) development wells; 28 (5.8 net) in Canada and 17 (8.1 net) in Oklahoma. In addition, 20 (10 net) wells were drilled on lands that are prospective for coal bed methane owned by the Trust in Wyoming.

In 2006 in Canada, the Trust spent $15.5 million in capital expenditures; $4.5 million related to drilling and completions operations, $4.4 million for the construction of facilities and pipelines, $2.3 million for other plant and equipment and $1.6 million for the completion equipping and tie-in of the deep gas well at Ricinus.

In Oklahoma in 2006, the Trust initiated an aggressive land acquisition program. During the year approximately US$4.5 million was spent to acquire lands for future development. In addition, during Q4 2006 the Trust drilled two salt water disposal wells at a total cost of approximately US$4.8 million. On occasion and as required, the Trust will drill further water disposal wells and make additions to existing facilities to support the dewatering efforts of the new wells being drilled under the farmout. During 2006 the trust also spent approximately US$1.5 million for infrastructure additions to support the locations being drilled. The capital cost of the disposal wells and infrastructure additions is recovered by the Trust over a 3 year period once the partner begins to fully utilize the facilities.

For 2007, the Trust plans to continue its capital additions through a combination of acquisitions and development activities. In Oklahoma, the Trust's undeveloped lands will continue to be developed under the existing farmout agreement allowing the Trust to minimize its capital expenditures while increasing the production base. In Canada, the Trust will continue to develop its existing land base as well as seek new areas for development

RESERVES AND PRESENT VALUE SUMMARY

The Trust complies with the National Instrument 51-101, issued by the Canadian Securities Administrators, in all its reserves related disclosures.

Proved reserves (P90) - For reported reserves this means there must be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Proved plus Probable (P50) - For reported reserves there must be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable reserves. The probable reserves will no longer be risked by 50 percent as they are implicitly risked due to the nature of the new definition of reserves.

The purpose of NI 51-101 is to enhance the quality, consistency, timeliness and comparability of oil and gas activities by reporting issuers and elevate reserves reporting to a higher level of accountability.

Reserve volumes and values at December 31, 2005 are based on the Trust's interest in its total proved and probable reserves prior to royalties as defined in NI 51-101. Reserve volumes and values for years prior to 2003 are based on "established" (proved plus 50% probable) reserves prior to deduction of royalties. Under those definitions, probable reserves were discounted by an arbitrary risk factor of 50% in reporting established reserves. Under NI 51-101 reserves definitions, estimates are prepared such that the full proved and probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "most likely case"). As such, the probable reserves reported are already "risked".

The Trust has its reserves evaluated by independent engineers each year. McDaniel and Associates Consultants Ltd. ("McDaniel") independently evaluated the 2006 Canadian reserves of the Trust, MHA Petroleum Consultants, Inc ("MHA") independently evaluated the Trust's affiliate Rocky Mountain Gas 2006 reserves and HAAS Petroleum Engineering Services, Inc evaluated the trusts Oklahoma reserves as at December 31, 2006.

RESERVE CONTINUITY
Oil and Gas (mboe)

	Proved	Probable	Total
December 31, 2004	7,385	2,024	9,409
Discoveries and extensions	47	14	61
Purchases (including East Central Properties acquisition)	9,784	5,020	14,804
Dispositions	–	–	–
Production	(2,825)	–	(2,825)
Revision of prior estimates	(96)	(2,321)	(2,417)
December 31, 2005	14,295	4,737	19,032
Discoveries and extensions	536	549	1,085
Purchases	15,041	1,961	17,002
Dispositions	(1,491)	(614)	(2,105)
Production	(4,508)	–	(4,508)
Revision of prior estimates	(2,655)	(494)	(3,149)
December 31, 2006	21,218	6,139	27,357

Proved plus probable reserves increased 44% from the end of 2005 to the end of 2006 primarily due to the Oklahoma Asset acquisition and ongoing development there and in Canada. Proved reserves increased 48% from 14,295 mboe to 21,218 mboe and probable reserves increased 30% from 4,737 mboe to 6,139 mboe. Total proved reserves represent 78% of total reserves versus 75% in 2005.

Discoveries and extensions of 1,085 mboe are primarily in Oklahoma. Revisions were both in Canada and the United States assets due to poorer than expected performance of new wells, changes in commodity price forecasts and increased operating expenditures due to increased cost of services. Divesting of non core assets in Canada resulted in 2,105 mboe reduction in proved plus probable reserves

Finding costs incurred over the last three years are highlighted below, along with the recycle ratios for each year. Management uses the recycle ratio to measure performance. It is calculated by dividing the netback per boe of production by the cost of per boe of finding and developing reserves. A recycle ratio of one is a "break even point", indicating that the cash flow from a unit of production is equal to the cost of finding and developing a unit of reserves.

Under NI 51-101, the methodology to be used to calculate finding, development and acquisition costs ("FD&A"), costs include incorporating changes in future development costs ("FDC") required to bring the proved undeveloped and probable reserves to production. For continuity the Trust has presented FD&A costs calculated both excluding and including FDC.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

FD&A AND RECYCLE RATIO

(in $/boe, except for capital expenditures which are in thousands)

	2006	2005	2004	3-year Average
Capital expenditures (excluding ARO)	$ 416,649	$ 419,679	$ 66,416	$ 300,522
Future Development Costs				
Proved	$ 10,101	$ 6,973	$ 589	$ 5,888
Proved Plus Probable	$ 15,002	$ 7,448	$ 589	$ 7,680
Reserves[1]				
Proved reserves added in the year (in mboe)	12,922	9,735	3,822	8,826
Probable reserves added in the year (in mboe)	2,016	2,713	(266)	1,488
Proved plus probable reserves added in the year (in mboe)	14,938	12,448	3,556	10,314
FD&A costs (excluding FDC)				
Proved reserves ($/boe)	32.24	43.11	17.38	34.05
Proved plus probable reserves ($/boe)	27.89	33.71	18.68	29.14
FD&A costs (including FDC)				
Proved reserves ($/boe)	33.03	43.83	17.53	34.72
Proved plus probable reserves ($/boe)	28.90	34.31	18.84	29.88
Corporate Netbacks ($/boe)[2]	19.49	25.98	21.06	22.18
Corporate recycle ratio (based on proved plus probable finding costs excluding FDC's)	0.70	0.77	1.13	0.87
Operating netbacks ($/boe)[3]	29.93	31.31	23.67	28.30
Operating recycle ratio (based on proved plus probable reserves excluding FDC's))	1.07	0.93	1.27	1.09

[1] Includes revisions and acquisitions
[2] Corporate netbacks are production revenue less royalties, operating costs, G&A and interest expense
[3] Operating netbacks are production revenue less royalties and operating costs

Finding costs and recycle ratios are non-GAAP financial measures that may not be comparable to similar measures presented by other entities.

The Trust reduced its proved plus probable FD&A excluding FDC costs from $33.71/boe to $27.89/boe. This was due to the acquisition of the Oklahoma Assets at lower metrics than the 2005 acquisitions.

ENTERRA ENERGY TRUST – ESTIMATED PETROLEUM AND NATURAL GAS RESERVES AND NET PRESENT VALUE

(December 31, 2006) (NPV in millions)

	Light/ Medium Oil (MBBL)	Heavy Oil (MBBL)	Natural Gas (MMCF)	NGL (MBBL)	Total (MBOE)	Net Present Value Before Income Tax ($) 0%	10%	15%
Canadian Assets								
McDaniel report								
Proved Producing	2,928	1,070	28,380	672	9,400	226	175	158
Proved Non-Producing	27	–	1,405	41	302	2	1	–
Proved Undeveloped	111	–	2,171	30	502	8	4	3
Total Proved	3,066	1,070	31,956	742	10,204	236	180	162
Total Probable	1,092	313	14,114	269	4,026	114	60	47
Total Proved & Probable	4,157	1,383	46,070	1,011	14,230	350	240	209
United States Assets								
Haas and MHA reports								
Proved Producing	1,423		43,602		8,690	215	158	139
Proved Non-Producing	55		2,364		449	11	8	7
Proved Undeveloped	319		9,337		1,875	68	44	37
Total Proved	1,797		55,303		11,014	294	210	183
Total Probable	202		11,470		2,114	58	40	34
Total Proved & Probable	1,999		66,773		13,128	353	250	217
Consolidated Assets								
Proved Producing	4,351	1,070	71,983	672	18,090	441	332	297
Proved Non-Producing	82	–	3,769	41	751	13	9	8
Proved Undeveloped	430	–	11,508	30	2,377	76	48	40
Total Proved	4,863	1,070	87,259	742	21,218	530	390	345
Total Probable	1,294	313	25,584	269	6,139	172	100	81
Total Proved & Probable	6,156	1,383	112,843	1,011	27,358	703	489	426

(1) The Haas and MHA reports were converted to Canadian dollars by the Trust using an exchange rate of US$0.87 per Canadian dollar.

LIQUIDITY & CAPITAL RESOURCES

The Trust's strategy is to both develop its own reserves and undeveloped land as well as have other companies spend the capital to develop its properties in exchange for a working interest. As well, the Trust continually seeks accretive acquisitions of oil and gas assets that will create new core areas with investment potential or will consolidate an existing core area. Any such capital expenditures or purchases by the Trust will be financed from cash flow, by issuing new equity and/or with debt.

In March 2006, the Trust closed a $110.0 million senior secured bridge facility. This reducing non-revolving credit facility was used to repay $100.0 million in existing credit facilities of the Trust

with the excess being added to the working capital. The bridge facility bore interest at 2.5% above bank prime lending rates. $2.0 million of the facility was repaid on June 30, 2006 with the remaining $108.0 million repaid on November 21, 2006. The facility was secured by a first charge over all Canadian assets of the Trust and a second charge over all US assets.

Also in March 2006, the Trust closed a US$200.0 million senior secured bridge credit facility to partially fund the acquisition of the Oklahoma Assets, repay US$50.0 million bridge credit facility and provide working capital to the Trust. This non-revolving facility originally bore interest at 4.5% above London Interbank Offering Rate and matured September 20, 2006. The Trust exercised a one-time option to extend the facility to December 20, 2006. As a result of this extension, the interest rate margin increased by 1% per month. The facility was repaid in full on November 21, 2006. The facility was secured by a first charge over all US assets and a second charge over all Canadian assets. The terms of the credit facility restricted the Trust's ability to withdraw more than US$1.5 million per month from the US segment.

On November 21, 2006, the Trust closed a $180.0 million revolving extendible credit facility and a $20.0 million revolving extendible operating credit facility. The $180.0 million and $20.0 million facilities are 364 day extendible facilities that are secured with a first priority charge over the Trust's assets. Borrowings under these facilities bear interest at banker's acceptance rates, Canadian or US prime rates, or LIBOR plus applicable margins ranging from nil to 1.65% depending on the form of borrowing and the Trust's debt to cash flow ratio. The current margin is 0.25% on prime rate borrowings and 1.4% on banker's acceptance rates or LIBOR borrowing. Should the lenders decline to extend the facilities at the end of the 364 day period, the facilities convert into one year term loans.

The facility requires the Trust to maintain certain financial covenants. As at December 31, 2006, the Trust is uncertain about its ability to meet certain of its covenant requirements for the first quarter of 2007, specifically the requirement that total distributions over the previous four quarters shall not exceed 100% of available cash flow over the period. As at March 31, 2007, the Trust's percentage of available cash flow distributed for the previous four quarters will remain high due to the US$0.18/unit distribution paid from April to July 2006 and the US$0.12/unit distribution paid from August 2006 to January 2007. As the current US$0.06/unit distribution continues, the Trust's ratio will improve. Should the Trust not meet the covenant at March 31, 2007, or subsequent periods, nor be able to obtain waivers from the lenders, the lenders could restrict distributions by the Trust and the facilities could become due and payable immediately.

The lenders are currently conducting their semi-annual review of the Trust's oil and gas reserves and borrowing base. Upwards or downwards adjustments to the size of the credit facility may arise from their review.

Also on November 21, 2006 the Trust issued $138.0 million of 8.0% unsecured subordinated debentures convertible into units at a price of $9.25 and $40.3 million of trust units at a price of $8.10. Proceeds from this issuance, together with drawings under the new revolving credit facilities, were used to repay the US$200.0 million senior secured bridge credit facility and the $110.0 million senior secured bridge facility.

On February 1, 2007, the $180.0 million revolving extendible credit facility was amended to be a $140.0 million revolving extendible credit facility with the same terms as the $180.0 million facility and a $40.0 million non-revolving credit facility. The $40.0 million facility is a second-lien credit facility that matures on November 20, 2007. Borrowings under the facility bear interest at Canadian or US prime rates plus a margin of 1.5%, or Canadian banker's acceptance rates or US LIBOR plus 2.5%. It is expected that the facility will not be repaid from internally generated cash flows or asset dispositions; therefore additional financing through the issuance of debt or equity will be required.

WORKING CAPITAL
(in thousands)

	Years Ended December 31, 2006	2005
Working capital (deficiency)	$ (188,683)	$ (112,397)
Working capital (deficiency) excluding debt	$ (529)	$ (16,947)

The working capital deficiencies mainly related to the classification of the bank indebtedness as current liabilities even though there is no expectation that the revolving lines of credit will be called by the bank.

The continued benefit of the cash flow from the Oklahoma Assets together with excess cash generated though the lowering of the target payout ratio in July 2006, effective with the payment of the August 2006 distribution, to between 60% and 70% are expected to provide strong cash flows for the Trust to fund its working capital requirements and capital expenditures.

CONTRACTUAL OBLIGATIONS

The Trust has two ongoing commitments over the next five years, one related to the capital lease and the other related to the rental payments for our office space. These commitments are outlined below:

PAYMENTS DUE BY PERIOD
(in thousands)

Contractual Obligations	*Total*	*Less than 1 year*	*1-3 years*	*3-5 years*	*More than 5 years*
Debt Obligations[1]	$ 188,154	$ 40,000	$ 147,797	$ –	$ 357
Interest on above debt[2]	20,555	12,019	8,422	–	114
Convertible debentures	80,331	–	–	80,331	–
Interest on convertible debentures[3]	32,132	6,426	19,279	6,427	–
Capital (Finance) Lease Obligations	1,702	1,702	–	–	–
Operating Lease Obligations	6,848	1,162	2,173	2,342	1,171
Purchase Obligations	–	–	–	–	–
Other Long-Term Liabilities Reflected on the Registrant's Balance Sheet under Canadian GAAP	28,447	2,000	–	–	26,447
Total	$ 358,169	$ 63,309	$ 177,671	$ 89,100	$ 28,089

[1] The bank debt is assumed to be repaid on November 20, 2008
[2] using the December 31, 2006 loan balance and its interest rate of 6.40%
[3] using the December 31, 2006 balance and its interest rate of 8.0%

At December 31, 2006 a claim in the amount of approximately US$3.9 million has been filed against the Trust related to its U.S. operations. The result of this claim is not determinable by the Trust. The Trust has also filed claims against the claimant.

Certain claims have been brought against the Trust in the ordinary course of business. In the opinion of management, all such claims, except as noted above, are adequately covered by insurance, or if not so covered, are not expected to materially affect the Trust's financial position.

RELATIONSHIP WITH JED

On January 1, 2006, the Trust terminated the Technical Services Agreement with JED under which JED provided certain administrative, management and technical services to the Trust. The Trust now manages its own management, development, exploitation, operations and general and administrative activities.

On February 1, 2006, the Trust repaid $8.0 million in unsecured notes payable to JED that had been outstanding at December 31, 2005.

On September 28, 2006, the Trust closed a property swap agreement with JED whereby the Trust swapped certain of its interests in properties in the Ferrier area of Alberta for interests of JED in common with the Trust in East Central Alberta, the Desan area of Northeast British Columbia and the Ricinus area of Alberta. The swap was based on independent third party engineering evaluations and was effective July 1, 2006. The transaction also resulted in the termination of the existing farmout, joint services agreements and the Agreement of Business Principles between the Trust and JED whereby the Trust had a right of first refusal on properties that JED owned and JED had the ability to farm-in on the Trust's undeveloped lands. Concurrent with the swap, the Trust settled all amounts owing to JED.

SUBSEQUENT EVENTS AND PROPOSED TRANSACTIONS

On February 21, 2007, the Trust entered into a purchase and sale agreement to purchase oil and natural gas properties from Petroflow for consideration of US$7.0 million. The purchase is subject to the fulfillment of certain conditions.

RELATED PARTY TRANSACTIONS

During 2006 the Trust paid $813,000 (2005 - $350,000) to Macon Resources Ltd. ("Macon"), a company 100% owned by the Chief Executive Officer of the Trust, for management services provided by the Chief Executive Officer and the previous Chief Financial Officer. The amounts have been recorded at the amounts agreed to by the related parties. At December 31, 2006 $nil (December 31, 2005 - $84,000) was payable by the Trust to Macon. During 2005, the Trust issued 400,000 trust unit options to Macon; the options have an exercise price of $23.96 per trust unit. The options have a 5-year life and vest over a 3-year period.

During 2006 the Trust entered into a farmout agreement with Petroflow, a public oil and gas company, to fund 100% of the drilling and completion costs of the Oklahoma Asset's undeveloped lands. The Chief Executive Officer of the Trust owns, directly and indirectly, approximately 14% of the outstanding shares of Petroflow. As at December 31, 2006, the Trust had US$1.5 million of receivables from Petroflow including $47,000 (US$ $40,000) related to processing fees charged to Petroflow. The receivables relate to costs incurred by the Trust as a result of the operations of the properties. The balances due are expected to be settled as part of the asset purchase discussed in note 22.

A director and an officer of the Trust have working interests in certain of the Oklahoma Assets. As a result balances will be payable or receivable from these individuals as a result of the operations of these properties. At December 31, 2006 no amounts were payable or receivable from the officer. During 2006, an adjustment period on the Oklahoma Asset acquisition concluded. As a result of the adjustment payment and the receivable balance related to the working interests, as noted above, the Trust owes the director $744,000 (US$638,000).

OFF BALANCE SHEET ARRANGEMENTS

There were no off balance sheet arrangements in 2006 or 2005 other than the operating leases discussed elsewhere in the MD&A.

TRUST UNIT INFORMATION

The Trust is capitalized through a combination of trust units and exchangeable shares of certain of its subsidiaries. The Trust also has a unit option plan, restricted unit plan, performance unit plan and warrants to purchase trust units outstanding. The following table outlines outstanding equity instruments:

OUTSTANDING UNIT DATA (units/shares)			
As at	March 20, 2007	December 31, 2006	December 31, 2005
Trust units	56,327,173	56,097,875	36,504,416
Exchangeable shares			
EEC exchangeable shares	–	16,337	348,146
RMG exchangeable shares	–	–	736,842
RMAC Series B exchangeable shares	–	66,720	659,116
Trust unit options	1,481,000	1,481,000	1,431,405
Restricted units	407,125	423,855	–
Performance units	213,790	212,948	–
Warrants	301,000	301,000	301,000
Convertible debentures ($1,000 per debenture)	80,331	80,331	–

SENSITIVITIES

The Trust is exposed to the normal risks inherent within the oil and gas sector, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. The Trust manages its operations in a manner intended to minimize exposure, as described in note 15 to the consolidated financial statements.

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of the Trust's accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. The Trust assesses the financial strength of its customers and joint venture partners through regular credit reviews in order to reduce the risk of non-payment.

Foreign Exchange Risk

The Trust is exposed to market risk from changes in the exchange rate between U.S. and Canadian dollars. For the Trust's Canadian operations, the price we receive for oil and natural gas production is based on a benchmark expressed in U.S. dollars, which is the standard for the oil and natural gas industry worldwide. However, operating expenses, drilling expenses and general overhead expenses are paid in Canadian dollars. The Trust's US operations receive revenue in U.S. dollars as well as pay the operating expenses, drilling expenses and general overhead expenses in U.S. dollars. Monthly distributions are paid on a value expressed in U.S. dollars. Within the Trust's bank indebtedness balance, $78.1 million (US$ 67.0 million) is denominated in U.S. dollars.

Changes to the exchange rate between U.S. and Canadian dollars can adversely affect the Trust. When the value of the U.S. dollar increases, the Trust receives higher revenue and when the value of the U.S. dollar declines, the Trust receives lower revenue on the same amount of production sold at the same prices. A change of $0.01 in the U.S. to Canadian dollar would impact the Trust's earnings by approximately $1.3 million and our cash provided by operating activities by $2.8 million.

Commodity Price Risk

The Trust's financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the Trust's control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect the Trust's financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that the Trust can produce economically. Any reduction in the Trust's oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on the Trust's ability to obtain capital for our development activities. Similarly, any improvements in oil and

natural gas prices can have a favorable impact on the Trust's financial condition, results of operations and capital resources. If the WTI oil price were to change by US$1.00 per bbl, the impact on earnings would be approximately $1.3 million and the impact on cash flow would be approximately $2.0 million. If natural gas prices were to change by US$0.50 per mcf, the impact on earnings would be approximately $6.0 million and the impact on cash provided by operating activities would be approximately $9.2 million.

The Trust uses financial derivatives and physical sales contracts to mitigate a portion of oil and natural gas price risk. While the use of these derivative arrangements limits the downside risk of price declines, such use may also limit any benefits that may be derived from price increases.

Interest Rate Risk

Interest rate risk exists principally with respect to indebtedness that bears interest at floating rates. At December 31, 2006, the Trust had $187.7 million of indebtedness bearing interest at floating rates. If interest rate were to change by one full percentage point, the net impact on earnings would be approximately $1.2 million and the net impact on our cash provided by operating activities would be approximately $1.9 million.

Summarized below are the Trust's sensitivities to various risks, based on its 2006 operations:

Sensitivity	Estimated 2006 Impact On: *(in thousands)*	
	Net Earnings	Cash Flow
Crude oil – US$1.00/bbl change in WTI	$ 1,291	$ 1,970
Natural gas – US$0.50/mcf change	$ 6,040	$ 9,222
Foreign exchange - $0.01 change in U.S. to Canadian dollar	$ 1,311	$ 2,829
Interest rate – 1% change	$ 1,229	$ 1,877

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's management, as appropriate, to allow timely decisions regarding required disclosure. The Trust's CEO and CFO have concluded, based on their evaluation as of December 31, 2006 (the "Evaluation Date"), that the Trust's disclosure controls and procedures as of the Evaluation Date are effective to provide reasonable assurance that material information related to the Trust, including its consolidated subsidiaries, is made know to them by others within those entities.

Internal Controls over Financial Reporting

Internal controls have been designed to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements together with the other financial information for external purposes in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The Trust's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting related to the Trust, including its consolidated subsidiaries.

The Trust's CEO and CFO are required to cause the Trust to disclose herein any change in the Trust's internal control over financial reporting that occurred during the Trust's most recent interim period that materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. During

2006, the Trust engaged external consultants to assist in documenting and assessing the Trust's design of internal controls over financial reporting. No material changes were identified in the Trust's internal control of financial reporting during the three months ended December 31, 2006, that had materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

It should be noted that a control system, including the Trust's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Changes to Internal Controls and Procedures for Financial Reporting

There were no significant changes to the Trust's internal controls or other factors that could significantly affect these controls subsequent to the Evaluation Date.

CRITICAL ACCOUNTING ESTIMATES

The Trust continues to evolve and document its management and internal reporting systems to provide assurance that accurate, timely internal and external information is gathered and disseminated. The Trust's financial and operating results incorporate certain estimates including:

a) estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;

b) estimated capital expenditures on projects that are in progress;

c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves, which the Trust expects to recover in the future;

d) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and

e) estimated future recoverable value of property, plant and equipment and goodwill.

NEW ACCOUNTING PRONOUNCEMENTS

In 2005, the CICA issued Handbook section 1530 – Comprehensive Income, 3855 – Financial Instruments: Recognition and Measurement, 3861 – Financial Instruments: Disclosure and Presentation and 3865 -Hedges which are effective for fiscal years beginning on or after October 1, 2006. These sections will be effective for the Trust commencing January 1, 2007. Under these new standards all financial assets are measured at fair value with the exception of loans, receivables and investments that are intended to be held until maturity. All financial liabilities are measured at fair value when they are either derivative or held for trading. Gains and losses on financial instruments measured at fair value will be recognized in earnings periods in which they occur, with the exception of gains and losses related to financial assets available for sale and financial instruments for which hedge accounting is applied. Unrealized gains and losses on qualified hedging instruments and financial assets available for sale are recorded to other comprehensive income and reclassified to earnings when ultimately realized. Other comprehensive income and its components will be required disclosures under the new sections.

The Trust believes that under the new standards fixed-price commodity contracts will be recognized as non-financial derivatives with the fair value included in the balance sheet and the difference in fair values being recorded in net earnings. The fair value determined will be recorded as a financial asset or liability on the balance sheet on January 1, 2007. The Trust is currently assessing other potential impacts of implementing these new sections.

ADDITIONAL INFORMATION

Additional information relating to Enterra Energy Trust, including our Annual Information Forms and Annual Reports, can be found on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar.shtml, as well as on the Trust's website at www.enterraenergy.com.

Abbreviations

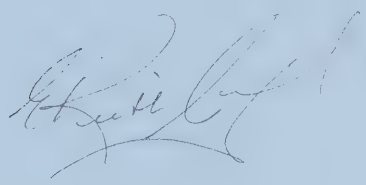
bbl	barrel of oil
bbls/day	barrels of oil per day
mcf	thousand cubic feet of natural gas
mcf/day	thousands of cubic feet of natural gas per day
NGL	natural gas liquids
boe	barrels of oil equivalent (6 mcf equivalent to 1 bbl)
mboe	thousands of barrels of oil equivalent
boe/day	barrels of oil equivalent per day
GJ	Gigajoule
mmbtu	millions of British Thermal Units
CICA	Canadian Institute of Chartered Accountants
GAAP	Canadian Generally Accepted Accounting Principles
Cdn$	Canadian dollars
US$	United States dollars
WTI	West Texas Intermediate (Oil reference price)
AECO	Natural gas reference price in Alberta
Nymex	New York Mercantile Exchange
Q1	first quarter of the year - January 1 to March 31
Q2	second quarter of the year - April 1 to June 30
Q3	third quarter of the year - July 1 to September 30
Q4	fourth quarter of the year - October 1 to December 31
mbbl	thousand barrels of oil
mmcf	millions of cubic feet of natural gas per day
mmbtu/day	millions of British Thermal Units per day
Mwh	megawatt-hour

MANAGEMENT'S REPORT TO THE UNITHOLDERS

Management is responsible for the preparation of the financial statements. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

Management is responsible for maintaining a system of internal controls that provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner. The Audit Committee of the Board of Directors meets periodically with management and the auditors to satisfy itself that management's responsibilities are properly discharged, to review the financial statements and to recommend approval of the financial statements to the Board.

External auditors, appointed by the unitholders, have examined the financial statements. The Audit Committee of the Board of Directors has reviewed the financial statements with management and the external auditors. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.



E. Keith Conrad
PRESIDENT & CEO

Calgary, Canada
March 23, 2007

AUDITOR'S REPORT TO THE UNITHOLDERS

We have audited the consolidated balance sheets of Enterra Energy Trust as at December 31, 2006 and 2005 and the consolidated statements of earnings (loss) and deficit and cash flow for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 23, 2007

CONSOLIDATED BALANCE SHEETS

(Thousands of Canadian Dollars)

	DECEMBER 31, 2006	DECEMBER 31, 2005
Assets		
Current assets		
Cash	$ 2,162	$ 11,943
Accounts receivable	38,980	35,303
Financial derivatives (note 15)	10,775	415
Prepaid expenses, deposits and other	3,249	3,052
	55,166	50,713
Property, plant and equipment (note 5)	659,268	489,074
Deferred financing charges	4,676	1,210
Goodwill (note 6)	76,256	70,546
	$ 795,366	$ 611,543
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 46,083	$ 38,414
Bank indebtedness (note 8)	188,154	95,450
Distribution payable to unitholders	7,910	7,699
Current portion of capital lease (note 10)	1,702	878
Due to JED Oil Inc. (note 21)	–	15,151
Note payable (note 9)	–	4,071
Marketing contracts	–	1,447
	243,849	163,110
Convertible debentures (note 11)	78,974	–
Asset retirement obligations (note 7)	28,447	24,323
Future income tax liability (note 14)	40,340	100,297
Capital lease (note 10)	–	1,702
	391,610	289,432
Non-controlling interest (note 12)	1,732	32,402
Unitholders' Equity (note 13)		
Unitholders' capital	635,134	373,761
Equity component of convertible debentures (note 11)	1,327	–
Warrants	1,215	1,215
Contributed surplus	3,195	573
Cummulative translation	1,930	–
Deficit	(240,777)	(85,840)
	402,024	289,709
Commitments and contingencies (notes 17 and 18)		
Subsequent events (notes 8, 15 and 22)	$ 795,366	$ 611,543

See accompanying notes to consolidated financial statements

Approved on behalf of the Board:

Keith Conrad
DIRECTOR

Joseph Vidal
DIRECTOR

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) AND DEFICIT (Thousands of Canadian Dollars, Except per Trust Unit Amounts)

	YEAR ENDED DECEMBER 31, 2006	YEAR ENDED DECEMBER 31, 2005
Revenues		
Oil and natural gas	$ 244,408	$ 158,097
Royalties	(48,288)	(36,079)
	196,120	122,018
Expenses		
Operating	50,361	32,620
General and administrative	20,374	10,331
Interest on current facilities	25,898	4,715
Interest on long term debt	819	–
Financing fees	5,447	–
Amortization of deferred financing charges	11,713	33
Depletion, depreciation and accretion (note 5)	135,429	68,229
Ceiling test impairment (note 5)	66,019	13,844
Goodwill impairment	–	9,253
Foreign exchange (gain) loss	1,910	(715)
	317,970	138,310
Earnings (loss) before taxes and non-controlling interest	(121,850)	(16,292)
Income taxes (note 14)		
Current	1,324	1,456
Future (reduction)	(58,899)	(18,689)
Earnings (loss) before non-controlling interest	(64,275)	941
Non-controlling interest (note 12)	(36)	(29)
Net earnings (loss)	(64,239)	970
Deficit, beginning of year	(85,840)	(17,314)
Distributions declared	(90,698)	(69,496)
Deficit, end of year	$ (240,777)	$ (85,840)
Net earnings (loss) per trust unit (note 13)		
Basic	$ (1.46)	$ 0.03
Diluted	$ (1.46)	$ 0.03

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOW

(Expressed in Thousands of Canadian Dollars)

	YEAR ENDED DECEMBER 31, 2006	YEAR ENDED DECEMBER 31, 2005
Cash provided by (used in):		
Operating		
Net earnings (loss)	$ (64,239)	$ 970
Depletion, depreciation, accretion and ceiling test impairment	201,448	82,073
Goodwill impairment	–	9,253
Future income tax reduction	(58,899)	(18,689)
Amortization of deferred financing charges	11,713	33
Financial derivatives	(10,628)	(415)
Financing fees	5,065	
Amortization of marketing contract	(1,447)	(2,667)
Non-controlling interest	(36)	(29)
Foreign exchange	1,038	(715)
Unit-based compensation	3,229	731
Loss on sale of assets	59	–
Cash paid on asset retirement obligations	(1,219)	–
Accretion on convertible debentures	33	–
Changes in non-cash working capital items (note 16)	(21,632)	(2,425)
	64,485	68,120
Financing		
Distributions paid	(90,487)	(66,195)
Increases in bank indebtedness (note 8)	587,818	(27,709)
Issuance of convertible debentures (note 11)	138,000	–
Repayment of bank indebtedness (note 8)	(510,353)	–
Notes payable (note 9)	(3,990)	4,300
Capital lease (note 10)	(878)	(805)
Deferred financing charges	(17,340)	(102)
Financing fees	(5,065)	–
Due to JED Oil Inc.	(2,009)	10,658
Issue of trust units, net of issue costs (note 13)	50,391	37,353
Exercise of trust unit options (note 13)	1,399	7,975
	147,486	(34,525)
Investing		
Property, plant and equipment additions	(30,918)	(31,217)
Proceeds on disposal of property, plant and equipment	6,586	–
Acquisition of Oklahoma assets (note 4)	(182,183)	–
Acquisition of Rocky Mountain Gas, net of cash (note 4)	–	(229)
Acquisition of High Point, net of cash (note 4)	–	1,282
Changes in capital accounts payable (note 16)	(7,645)	3,733
	(214,160)	(26,431)
Foreign exchange on financial balances	(7,592)	–
Change in cash	(9,781)	7,164
Cash, beginning of year	11,943	4,779
Cash, end of year	$ 2,162	$ 11,943

See accompanying notes to consolidated financial statements

1. STRUCTURE OF THE TRUST AND BASIS OF PRESENTATION

Enterra Energy Trust ("the Trust") was established in November 2003 under a Plan of Arrangement. The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture (the "Trust Indenture"). The purpose of the Trust is to indirectly hold interests in petroleum and natural gas properties, through notes from, and investments in securities of its subsidiaries. The beneficiaries of the Trust are the holders of the trust units (the "Unitholders").

The Trust is required to pay monthly cash distributions to its Unitholders in amounts equal to the net earnings of the Trust earned from interest income on the notes and from any dividends or note redemptions by the Trust's subsidiaries less any expenses of the Trust. The Board of Directors of Enterra Energy Corp. ("EEC"), as administrator of the Trust, has the discretion to determine the extent to which cash, in excess of the above noted interest income and dividends, will be distributed to the Unitholders.

2. SIGNIFICANT ACCOUNTING POLICIES

Management of the Trust has prepared the consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The significant differences between Canadian and United States GAAP are outlined in note 23. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements, and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

These consolidated financial statements include the accounts of the Trust and its subsidiaries and partnerships (collectively the "Trust" for purposes of the following notes to the consolidated financial statements). All inter-company accounts and transactions have been eliminated.

Substantially all exploration, development and production activities related to the Trust's oil and gas business are conducted jointly with others and the accounts reflect only the Trust's proportionate interest.

(b) Cash and Cash Equivalents

Cash consists of cash on hand and balances invested in short-term securities with original maturities less than 90 days at the date of acquisition.

(c) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Trust to its customers based on contracts which establish the price of products sold and when collection is reasonably assured.

(d) Petroleum and Natural Gas Properties

The Trust follows the "full cost" method of accounting for petroleum and natural gas properties. All costs related to the exploration for and the development of oil and gas reserves are capitalized into one of two cost centers, Canada and the United States. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling productive and non-productive wells and production equipment.

General and administrative costs are capitalized if they are directly related to development or exploration projects.

Proceeds from the disposal of oil and natural gas properties are applied as a reduction of cost without recognition of a gain or loss except where such disposals would result in a 20% change in the depletion rate.

Repair and maintenance costs are expensed as incurred.

(e) Impairment Test

The Trust places a limit on the carrying value of property and equipment, which may be depleted against revenues of future periods (the "ceiling test"). The ceiling test is conducted separately for each cost center, Canada and the United States. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value of the cost center. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of petroleum and natural gas properties exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. The carrying value of property and equipment subject to the ceiling test includes asset retirement costs.

(f) Per Unit Amounts

Per unit amounts are calculated using the weighted average number of units outstanding. The Trust follows the treasury stock method to determine dilutive effect of options, warrants and other dilutive instruments. Under the treasury stock method, only "in-the-money" dilutive instruments impact the diluted calculations. Exchangeable shares are included in the calculation of diluted earnings per unit based on the number of trust units that would be issued on conversion of the exchangeable shares at the end of the year as long as the conversion results in a decrease to earnings of the Trust. Convertible debentures are included in the calculation of diluted earnings per unit based on the number of trust units that would be issued on conversion of the convertible debentures at the end of the year and an add-back of the associated interest expense for the year as long as the conversion results in a dilution to the Trust.

(g) Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenue and expenses during the reporting periods.

The amounts recorded for depletion, depreciation and the asset retirement obligation are based on estimates. The ceiling test calculation is based on estimates of reserves, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

The amounts recorded for financial derivatives are based on estimates of the price for oil and natural gas in future periods. These estimates are subject to fluctuations in market prices and will impact the consolidated financial statements of future periods.

The amount recorded for goodwill is tested for impairment based on estimates of the fair value of the Trust's reporting units. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

(h) Depletion and Depreciation

The provision for depletion of petroleum and natural gas properties is calculated, by cost center, using the unit-of-production method based on the Trust's share of estimated proved reserves before royalties. Natural gas reserves and production are converted to equivalent units of crude oil using their approximate relative energy content.

Office furniture and equipment is depreciated on a 20% declining balance basis.

(i) Goodwill

The Trust recognizes goodwill relating to acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. To assess impairment, the estimated fair value of a reporting unit is compared to its book value. If the fair value is less than the book value, a second test is performed to determine the amount of impairment. The amount of impairment is measured by allocating the estimated fair value to a reporting unit's identifiable assets and liabilities as if it had been acquired in a business combination for a purchase price equal to its estimated fair market value. If goodwill determined in this manner is less than the carrying value of goodwill, an impairment loss is recognized in the period in which it occurs. Goodwill is stated at cost less impairment. Goodwill is tested for impairment separately for the Canadian and the United States reporting units.

(j) Asset Retirement Obligations

The Trust recognizes a liability for the estimated fair value of the future retirement obligations associated with property and equipment. The fair value of the estimated asset retirement obligations is recorded as a liability with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The Trust estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is prospectively applied. As time passes, the change in net present value of the future retirement obligation is expensed through accretion. Retirement obligations settled during the period reduce the future retirement liability.

(k) Income Taxes

The Trust is a taxable entity under the Canadian Income Tax Act and is taxable only on income that is not distributed or distributable to the Trust's unitholders. As the Trust allocates all of its taxable income to the unitholders in accordance with the Trust Indenture, therefore no provision for income tax expense has been made in the Trust.

The Trust's corporate subsidiaries follow the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized based on the differences between the amounts reported in the financial statements of the Trust's corporate subsidiaries and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(l) Non-controlling Interest

TheTrust has, through its subsidiaries four types of exchangeable shares that are classified as non-controlling interest on the consolidated balance sheets. Income after tax attributable to these exchangeable shares is deducted from net earnings of the Trust on the consolidated statement of earnings (loss).

When the EEC exchangeable shares are exchanged for trust units, they are measured at the fair value of the trust units issued. The amounts in excess of the carrying value of exchangeable shares are allocated to property, plant and equipment, to the extent possible, with any excess amounts being allocated to goodwill. When the other exchangeable shares, which were initially recorded at estimated fair value, are exchanged for trust units, they are measured at their carrying value.

(m) Derivative Financial Instruments

The Trust uses derivative financial instruments such as collars and swaps to manage its exposure to commodity price fluctuations. Actual amounts received, or paid, on the settlement of the derivative financial instruments are recorded in oil and

gas revenue. The Trust uses the fair value method for reporting derivative financial instruments whereby a derivative financial instrument is recorded as an asset or a liability on the balance sheet, and changes in the fair value during to a financial period are recorded in oil and natural gas revenue.

(n) Trust Unit Compensation Plans

The Trust has multiple unit based compensation plans, which are described in note 13. Compensation expense associated with each unit based compensation plan is recognized in earnings over the vesting period of the plan with a corresponding increase in contributed surplus. Any consideration received upon the exercise of the unit based compensation together with the amount of non-cash compensation expense recognized in contributed surplus is recorded as an increase in unitholders' capital. Compensation expense is based on the fair value of the unit based compensation at the date of grant.

(o) Deferred Financing Charges

Deferred financing charges are amortized over the lives of the related debt.

(p) Foreign Currency Transactions

Transactions completed in United States dollars are reflected in Canadian dollars at the exchange rates prevailing at the time of the transactions. Current assets and liabilities denominated in United States dollars are reflected in the financial statements at the Canadian equivalent at the rate of exchange prevailing at the balance sheet date. Translation gains and losses are included in earnings.

The Trust's U.S. subsidiaries are considered to be "self sustaining operations". As a result, the revenues and expenses are translated to Canadian dollars using average exchange rates for the period. Assets and liabilities are translated at the period-end exchange rate. Gains or losses resulting from the translation are included in the cumulative translation account in unitholders' equity.

(q) Comparative Figures

Certain comparative figures have been reclassified to conform with the presentation adopted in the current year.

3. PROPERTY ACQUISITIONS

In January 2005, the Trust acquired certain oil and natural gas properties in east central Alberta for consideration of $12,100,000. Results from operations of these acquired assets are included in the Trust's consolidated financial statements for the period subsequent to January 26, 2005.

4. CORPORATE ACQUISITIONS

Oklahoma Assets ("Oklahoma Assets")

During 2006, the Trust acquired oil and natural gas properties located in Oklahoma. The Trust acquired the assets in four stages.

Prior to closing the acquisitions, the Trust acquired $49.7 million of notes payable by the primary vendors of the Oklahoma Assets; as a result the vendors owed the Trust $49.7 million. The primary vendors repaid the Trust $38.5 million of the notes upon closing the second stage of the acquisition of the Oklahoma Assets. The acquisition of the notes, by the Trust, was financed with a US$50.0 million senior bridge credit facility.

On January 18, 2006, the Trust closed the first stage of the acquisition of the Oklahoma Assets. The results of the operations of the assets acquired are included in the Trust's consolidated financial statements as of January 18, 2006.

On March 21, 2006, the Trust closed the second stage of the acquisition of the Oklahoma Assets. Along with the second stage, the Trust acquired the operating company of the Oklahoma Assets. The results of operations of the assets acquired and the operating company are included in the Trust's consolidated financial statements as of March 21, 2006.

On April 4, 2006, the Trust closed the third stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 4, 2006.

On April 18, 2006, the Trust closed the fourth stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 18, 2006.

The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:	
Current assets	$ 6,412
Property, plant and equipment	352,999
Current liabilities	(25,355)
Financial derivatives	(485)
Debt	(24,036)
Asset retirement obligations	(1,926)
	$ 307,609

Cost of acquisition:	
Cash paid and payable	$ 181,044
Transaction costs	10,040
5,685,028 trust units	116,525
	$ 307,609

The purchase price allocation is preliminary and subject to change. The value assigned to each Enterra trust unit of $20.51 (US$17.70) was based on the weighted average trading price immediately prior to the measurement date. The acquisition provides cash flows from currently producing assets and provides the opportunity for the exploitation of the undeveloped lands.

As a result of adjustments to the purchase price, as determined by the purchase and sale agreements, the Trust owes $8,902,000 (US$7,639,000) to the vendors as at December 31, 2006.

Rocky Mountain Gas, Inc. ("RMG")

On June 1, 2005, the Trust acquired 100% of the issued and outstanding shares of RMG, an entity with natural gas properties in Montana and Wyoming. As RMG's properties are in the United States, they constitute a second cost center. RMG provides the Trust with future cash potential through the exploitation of coal bed methane on its undeveloped land as well as its currently producing assets. Results from operations of RMG subsequent to June 1, 2005 are included in the Trust's consolidated financial statements.

The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:	
Current assets, including cash of $769	$ 1,606
Property, plant and equipment	34,809
Goodwill (with no tax base)	9,253
Marketing contract	(480)
Current liabilities	(1,562)
Debt	(4,229)
Asset retirement obligations	(3,807)
Future income tax liability	(11,619)
	$ 23,971

Cost of acquisition:	
Cash	$ 602
Transaction costs	396
736,842 RMG exchangeable shares	16,722
275,474 Trust Units	6,251
	$ 23,971

The value assigned to each Enterra trust unit of $22.69 (US$18.35) was based on the weighted average trading price immediately prior to and after the measurement date.

High Point Resources Inc. ("High Point")

On August 17, 2005 the Trust completed the acquisition of 100% of the common shares of High Point through its subsidiary Rocky Mountain Acquisition Corp. ("RMAC") in exchange for 7,490,898 trust units and 1,407,177 RMAC exchangeable shares. High Point owns oil and natural gas properties predominantly in Alberta and British Columbia. The acquisition was completed to increase the Trust's natural gas portfolio. Results from operations of High Point subsequent to August 17, 2005 are included in the Trust's consolidated financial statements.

The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:	
Current assets, including cash of $2,532	$ 12,306
Property, plant and equipment	351,385
Goodwill (with no tax base)	19,070
Current liabilities	(14,779)
Marketing contract	(3,634)
Debt	(75,000)
Asset retirement obligations	(2,653)
Future income tax liability	(85,239)
	$ 201,456

Cost of acquisition:	
7,490,898 Trust Units	$ 168,545
1,407,177 Exchangeable Shares	31,661
Transaction costs	1,250
	$ 201,456

The value assigned to each trust unit and exchangeable share of $22.50 was based on the average trading price for the period prior to and after the measurement date.

5. PROPERTY, PLANT AND EQUIPMENT

	2006		
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	$ 1,011,399	$ 355,304	$ 656,095
Office furniture and equipment	5,118	1,945	3,173
	$ 1,016,517	$ 357,249	$ 659,268

	2005		
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	$ 644,260	$ 156,445	$ 487,815
Office furniture and equipment	2,781	1,522	1,259
	$ 647,041	$ 157,967	$ 489,074

During 2006, $nil of general and administrative expenses were capitalized and included in the cost of the petroleum and natural gas properties (2005 - $49,000).

At December 31, 2006, included in petroleum and natural gas properties are assets acquired and pledged under capital lease agreements with a cost base of $5,218,000 and net book value of $2,055,000 (2005 - $5,218,000 and $2,597,000).

At December 31, 2006 costs of undeveloped land and seismic of $25,876,000 (2005 - $58,353,000) were excluded from and $8,018,000 (2005 - $7,385,000) of future development costs were added to the calculation of depletion expense for the Canadian cost centre. At December 31, 2006 costs of undeveloped land of $16,848,000 (2005 – $13,313,000) were excluded from and $3,480,000 (2005 - $1,080,000) of future development costs were added to the calculation of depletion expense for the United States cost centre.

Depletion and depreciation expense related to the Canadian and the US cost center in 2006 was $90,677,000 and $42,587,000 respectively (2005 – $64,626,000 and $2,160,000).

The Trust completed ceiling test calculations for the Canadian and U.S. cost centers at December 31, 2006 to assess the recoverability of costs recorded in respect of the petroleum and natural gas properties. The petroleum and natural gas prices are based on the December 31, 2006 commodity price forecast of our independent reserve engineers. The following table summarizes the benchmark prices used in the ceiling test calculation.

Year	WTI Oil (US$/bbl)	Foreign Exchange Rate	Edmonton Light Crude Oil ($/bbl)	AECO Gas ($/GJ)	Henry Hub (US$/Mmbtu)
2007	62.50	1.1494	70.80	6.85	7.40
2008	61.20	1.1494	69.30	7.05	7.60
2009	59.80	1.1494	67.70	7.40	7.95
2010	58.40	1.1494	66.10	7.50	8.05
2011	56.80	1.1494	64.20	7.70	8.25
2012	58.00	1.1494	65.60	7.90	8.50
Escalate Thereafter	Average 2% per year	1.1494	Average 2% per year	Average 2% per year	Average 2% per year

The ceiling test in the Canada cost center resulted in a write down of $48,779,000 ($34,389,000 after tax and a loss of $0.78 per unit) to property plant and equipment at December 31, 2006.

The ceiling test in the U.S. cost center resulted in a write down of $17,239,000 ($10,343,000 after tax and a loss of $0.23 per unit) to property plant and equipment at December 31, 2006.

6. GOODWILL

As at December 31, 2005 due to the reduction in value of the U.S. cost center, goodwill in the United States reporting unit was deemed to be impaired. Accordingly, the Trust recorded a goodwill impairment loss of $9,253,000 in 2005. As at December 31, 2006 all of the goodwill was related to the Canada cost center.

	2006	2005
Goodwill, beginning of year	$ 70,546	$ 49,270
Acquisition of RMG	–	9,253
Acquisition of High Point	–	19,070
Acquisition adjustment of RMEC	–	771
Exchanges of Enterra Energy Corp. exchangeable shares	5,710	1,435
Impairment loss	–	(9,253)
Goodwill, end of year	$ 76,256	$ 70,546

7. ASSET RETIREMENT OBLIGATIONS

The asset retirement obligations were estimated by management based on the Trust's working interest in its wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred. At December 31, 2006, the Trust estimated the asset retirement obligation to be $28,447,000 (2005 – $24,323,000), based on a total future liability of $49,442,000 (2005 - $41,074,000). These obligations will be settled at the end of the useful lives of the underlying assets, which currently averages at 6 years, but extends up to 21 years into the future. This amount has been calculated using an inflation rate of 2% and discounted using a credit-adjusted risk-free interest rate of 8%.

The following table reconciles the asset retirement obligations:

	2006	2005
Asset retirement obligation, beginning of year	$ 24,323	$ 14,836
Increases in liabilities during the year related to:		
Acquisitions	1,926	6,460
Additions	1,281	1,911
Revisions	2,000	(327)
Accretion expense	2,166	1,443
Dispositions	–	–
Costs incurred	(3,178)	–
Foreign exchange	(71)	–
Asset retirement obligation, end of year	$ 28,447	$ 24,323

8. BANK INDEBTEDNESS

On November 21, 2006, the Trust closed a $180 million revolving extendible credit facility and a $20 million revolving extendible operating credit facility. As at December 31, 2006, the Trust had $187.7 million of borrowings (of which $77.1 million was denominated in U.S. dollars) and $194,000 of letters of credit drawn on the facilities. The $180 million and $20 million facilities are 364 day extendible facilities that are secured with a first priority charge over the Trust's assets. Borrowings under these facilities bear interest at banker's acceptance rates, Canadian or US prime rates, or LIBOR plus applicable margins ranging from nil to 1.65% depending on the form of borrowing and the Trust's debt to cash flow ratio. At December 31, 2006 the margin was 0.25% on prime rate borrowings and 1.4% on banker's acceptance rates or LIBOR borrowing. Should the lenders decline to extend the facilities at the end of the 364 day period, the facilities convert into one year term loans.

The credit facilities require the Trust to maintain certain financial covenants. As at December 31, 2006, the Trust was in compliance with all of the covenants. The Trust is uncertain about its ability to meet certain of its covenant requirements for the first quarter of 2007, specifically the requirement that total distributions over the previous four quarters not exceed 100% of available cash flow over the period. As a result, the Trust has classified its bank indebtedness as a current liability. Should the Trust not meet the covenant at March 31, 2007 or subsequent periods nor be able to obtain waivers from the lenders, the lenders could restrict distributions by the Trust and the bank debt could become due and payable immediately.

The lenders are currently conducting their semi-annual review of the Trust's oil and gas reserves and borrowing base. Upwards or downwards adjustments to the size of the credit facility may arise from their review.

On February 1, 2007, the $180 million revolving extendible credit facility was amended to be a $140 million revolving extendible credit facility with the same terms as the $180 million facility and a $40 million non-revolving credit facility. The $40 million facility is a non-revolving credit facility that matures on November 20, 2007 and is subordinated to the $140 million revolving facility. Borrowings under this facility bear interest at banker's acceptance rates, Canadian or US prime rates, or LIBOR plus applicable margins ranging from 2.0% to 3.0% depending on the form of borrowing. It is expected that the facility will not be repaid from internally generated cashflows or asset dispositions; therefore additional financing through the issuance of debt or equity will be required.

The Trust also has the following credit facilities:

A building mortgage, secured by the building, that bears interest at 7% per annum. The facility matures on July 1, 2020. As at December 31, 2006, the loan had a balance of $0.4 million (US$0.3 million).

A promissory note, used to acquire, and secured by, equipment owned by the Trust. The note matures on February 20, 2009 and bears interest at US prime plus 1%. At December 31, 2006, the balance of the note was $0.1 million (US$0.1 million).

In March 2006, the Trust closed a $110.0 million senior secured bridge facility. This reducing non-revolving credit facility was used to repay the existing $100.0 million credit facilities of the Trust. The facility bore interest at 2.5% above bank prime lending rates. $2.0 million of the facility was repaid on June 30, 2006 with the remaining $108.0 million repaid on November 21, 2006.

In March 2006, the Trust closed a US$200.0 million senior secured bridge credit facility to fund the acquisition of the Oklahoma Assets. The facility bore interest at 4.5% above London Interbank Offering Rate. The facility was repaid on November 21, 2006.

At December 31, 2005, the Trust had available two revolving lines of credit that totaled $100,000,000 ($95,000,000 revolving facility and $5,000,000 operating facility). Drawings on the revolving facilities bore interest at 0.25% above the bank's prime lending rate or bankers' acceptance rates plus margins which were 135 basis points. Security was provided by a first charge over all of the Trust's assets. As at December 31, 2005, the Trust had $95,450,000 drawn on the facilities at an interest rate of 5.25%. In March 2006, the credit facilities were replaced by the senior secured bridge facility ($110.0 million).

9. NOTE PAYABLE

Note payable consisted of an unsecured promissory note for US$3.5 million (Cdn $4.1 million), which bore interest at 12%, and was repaid in 2006.

10. CAPITAL LEASE OBLIGATION

Description	2006	2005
Capital lease bearing interest at 8.605%, repayable monthly at $88,802, including interest. The lease term is for 60 months, due October 1, 2007, with a purchase option of $1,000,000 and secured by the related equipment	$ 1,702	$ 2,580
Less current portion	(1,702)	(878)
	–	$ 1,702

Interest expense includes $188,000 (2005 - $260,000) related to the capital lease.

11. CONVERTIBLE DEBENTURES

The Trust's convertible debentures are classified as debt with a portion of the proceeds allocated to equity representing the value of the conversion option. If the debentures are converted to Trust units, the debt and equity components are transferred to Unitholders' capital. The debt balance associated with the convertible debentures accretes over time to the amount owing on maturity with such increases reflected as non-cash interest expense in the statement of earnings (loss).

On November 21, 2006, the Trust issued $138,000,000 of convertible debentures with a face value of $1,000 per convertible debenture that mature on December 31, 2011, bear interest at 8% per annum paid semi-annually on June 30 and December 31 of each year with the first payment occurring in 2007 and are subordinated to the bank credit facilities. The convertible debentures are convertible at the option of the holder into trust units at any time prior to the maturity date at the conversion price of $9.25 per trust unit. During 2006, convertible debentures were converted, resulting in the issuance of 6,234,483 trust units.

At the option of the Trust, the repayment of the principal portion of the convertible debentures may be settled in trust units. The number of trust units issued upon redemption by the Trust will be calculated by dividing the principal by 95% of the weighted average trading price of trust units. The convertible debentures are not redeemable on or before December 31, 2009. On or after January 1, 2010 and prior to maturity, the convertible debentures may be redeemed in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 30 days notice, at a redemption price of $1,050 per convertible debenture after December 31, 2009, on or before December 31, 2010, at a redemption price of $1,050 per convertible debenture and on or after January 1, 2011 and prior to maturity at a redemption price of $1,025 per convertible debenture, in each case, plus accrued and unpaid interest thereon, if any.

At December 31, 2006, the Trust had $80.3 million in convertible debentures outstanding with an estimated fair value of $80.9 million.

Convertible debentures	Equity Component	Liability Component
November 21, 2006 issuance	$ –	$ 138,000
Portion allocated to equity	2,387	(2,387)
Issue costs	(107)	–
Accretion of non-cash interest expense	–	33
Converted into trust units	(953)	(56,672)
	$ 1,327	$ 78,974

12. NON-CONTROLLING INTEREST

Number of exchangeable shares issued	EEC	RMAC series A	RMG	RMAC series B	Total
Balance at December 31, 2004	410,770	142,444	–	–	553,214
Issued on acquisition of RMG	–	–	736,842	–	736,842
Issued on acquisition of High Point	–	–	–	1,407,177	1,407,177
Exchanged for trust units	(62,624)	(142,444)	–	(748,061)	(953,129)
Balance at December 31, 2005	348,146	–	736,842	659,116	1,744,104
Exchanged for trust units	(331,809)	–	(736,842)	(592,396)	(1,661,047)
Balance at December 31, 2006	16,337	–	–	66,720	83,057

Non-controlling interest	Amount
Balance at December 31, 2004	$ 3,349
Issued on acquisition of RMG	16,722
Issued on acquisition of High Point	31,661
Exchanged for trust units	(19,301)
Non-controlling interest share of net earnings	(29)
Balance at December 31, 2005	$ 32,402
Exchanged for trust units	(30,634)
Non-controlling interest share of net earnings	(36)
Balance at December 31, 2006	$ 1,732

During January 2007, the remaining exchangeable shares were converted into trust units.

With the exception of the RMG exchangeable shares, the exchangeable shares are convertible at any time into trust units (at the option of the holder) based on the exchange ratio. The exchange ratio for RMAC series A exchangeable shares, RMAC series B exchangeable shares and Enterra Energy Corp. exchangeable shares are increased monthly based on the cash distribution paid on the trust units divided by the ten day weighted average unit price preceding the distribution payment date. Cash distributions are not paid on the exchangeable shares. On the third anniversary of the issuance of the exchangeable shares, subject to extension of such date by the Board of Directors of the Trust, or at the Trust's option when the aggregate number of issued and outstanding exchangeable shares is less than 1,000,000, the exchangeable shares will be redeemed for trust units at a redemption price per exchangeable share equal to the value of that number of trust units equal to the exchange ratio as at that redemption date. RMG exchangeable shares did not have an exchange ratio and were exchanged automatically for one trust unit on June 1, 2006. The exchangeable shares are not listed for trading on an exchange.

During 2006, a total of 331,809 Enterra Energy Corp. exchangeable shares were converted into 422,397 trust units at an exchange ratio prevailing at the time of conversion (2005 – 62,624, exchangeable shares were converted into 73,432 trust units). During 2006 a total of 592,396 RMAC series B exchangeable shares were converted into 619,945 trust units at an exchange ratio prevailing at the time of conversion (2005 – 748,061 exchangeable shares were converted into 758,109 trust units). The exchange of the EEC exchangeable shares is treated as a step acquisition which increases goodwill by $5.7 million (2005 – $1.4 million) for the difference between the fair value of the trust unit issued and the carrying value of the EEC exchangeable share at the time of exchange.

At December 31, 2006, the exchange ratio for Enterra Energy Corp. exchangeable shares was 1.39937 (2005 - 1.20694) and for RMAC series B exchangeable shares was 1.19626 (2005 - 1.03175).

13. UNITHOLDERS' EQUITY

Authorized trust units

An unlimited number of trust units may be issued.

The trust units are redeemable at the option of the holder based on the lesser of 90% of the average market trading price of the trust units for the 10 trading days after the date of redemption or the closing market price of the trust units on the date of redemption. Trust units can be redeemed to a cash limit of $100,000 per year or a greater limit at the discretion of the Trust. Redemptions in excess of the cash limit shall be satisfied first by the issuance of notes by a subsidiary of the Trust and second by issuance of promissory notes by the Trust.

Issued trust units

	Number of Units	Amount
Balance at December 31, 2004	25,426,800	$ 132,207
Issued on exercise of options	536,762	8,211
Issue pursuant to acquisition of RMAC	38,726	771
Issue pursuant to acquisition of RMG	275,474	6,251
Issue pursuant to acquisition of High Point	7,490,898	168,545
Issued pursuant to private placements	1,756,579	38,110
Issued for exchangeable shares	979,177	20,587
Unit issue costs	–	(921)
Balance at December 31, 2005	36,504,416	$ 373,761
Issued for cash pursuant to private placements	657,500	12,544
Issued on acquisition of Oklahoma Assets (note 4)	5,685,028	116,525
Issued for cash pursuant to prospectus offering	4,979,500	40,334
Issued on conversion of convertible debentures (note 11)	6,234,483	57,625
Issued as financing fees on bridge credit facilities	116,054	2,077
Issued for exchangeable shares	1,779,184	36,502
Issued under restricted unit plan	41,805	579
Issued on exercise of options	99,905	1,427
Unit issue costs	–	(6,240)
Balance at December 31, 2006	56,097,875	$ 635,134

Warrants

In April 2005 as part of an agreement to issue equity, the Trust granted warrants to Kingsbridge Capital Limited ("Kingsbridge") to purchase 301,000 trust units. The warrants have a three-year term. The exercise price of the warrants was initially US$25.77 per trust unit and is reduced each month by the amount of the Trust's distribution for such month on the trust units, provided that the price shall not decrease below US$21.55 per trust unit. As at December 31, 2006 the exercise price of the warrants was US$22.65. At December 31, 2006, the fair value of the warrants has been included in trust unit issue costs.

The fair value of the warrants was estimated using the Black-Scholes model under the following assumptions:

Weighted-average fair value of warrants granted ($/warrant)	$ 4.04
Risk-free interest rate (%)	3.6
Estimated hold period prior to exercise (years)	3
Weighted-average volatility (%)	33
Cash distribution yield (%)	9

Contributed surplus

Balance at December 31, 2004	$ 78
Trust unit option based compensation	731
Transfer to trust units option exercises	(236)
Balance at December 31, 2005	$ 573
Trust unit option based compensation	1,294
Restricted and performance unit compensation	1,935
Transfer to trust units on restricted and performance unit exercises	(579)
Transfer to trust units on option exercises	(28)
Balance at December 31, 2006	$ 3,195

Cumulative Translation

Balance at December 31, 2005	$ —
Cumulative translation of self-sustaining operations	1,082
Foreign exchange loss realized	848
Balance at December 31, 2006	**$ 1,930**

Trust unit options

Enterra has granted trust unit options to directors, officers, employees and consultants of the Trust. Each trust unit option permits the holder to purchase one trust unit at the stated exercise price. All options vest over a 3-year period and have a term of 5 years. At the time of grant, the exercise price is equal to the market price.

The following options have been granted:

	2006		2005	
	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price
Options outstanding, beginning of year	1,431,405	$ 22.31	950,000	$ 14.22
Options granted	752,000	15.70	1,461,500	23.88
Options exercised	(99,905)	14.00	(536,762)	14.86
Options forfeited	(602,500)	23.62	(443,333)	17.15
Options outstanding, end of year	1,481,000	$ 20.28	1,431,405	$ 22.31
Options exercisable at end of year	254,666	$ 23.85	69,905	$ 14.98

	Unit options outstanding		Unit options exercisable	
Exercise price range	Number of options	Weighted average remaining contract life	Number of options	Weighted average remaining contract life
$13.48 to $20.12	723,000	4.32	15,000	3.97
$23.15 to $29.31	758,000	3.47	239,666	3.43
	1,481,000	3.89	254,666	3.47

Estimated fair value of stock options

The estimated fair value of options was determined using the Black-Scholes model under the following assumptions:

	2006	2005
Weighted-average fair value of options granted ($/option)	$ 1.07	$ 2.35
Risk-free interest rate (%)	4.2	3.7
Estimated hold period prior to exercise (years)	5	5
Expected volatility (%)	45	36
Expected cash distribution yield (%)	14	10

Restricted and Performance units

The Trust has granted restricted and performance units to directors, officers and employees of the Trust. Restricted units ("RU's") vest over a contracted period and provide the holder with trust units on the vesting dates of the RU's. The actual units granted is based on the number of restricted units granted times a multiplier. The multiplier starts at 1.0 and is adjusted each month based on the monthly distribution of the Trust divided by the five day weighted average price of the Trust's units based on the New York Stock Exchange for the period preceding the distribution date. Performance units ("PU's") vest at the end of two years and provide the holder with trust units based on the same multiplier as the RU's as well as a payout multiplier. The payout multiplier ranges between 0.0 and 2.0 based on the Trust's total unitholder return compared to its peers. As at December 31, 2006 the payout multiplier was estimated to be nil based on the Trust's total unitholder return compared to its peers.

The following restricted and performance units have been granted:

	Number of restricted units	Weighted-average grant date fair value	Number of performance units	Weighted-average grant date fair value
Units outstanding, December 31, 2005	–	$ –	–	$ –
Granted	479,466	14.90	215,119	15.06
Vested	(44,375)	15.08	–	–
Forfeited	(11,236)	15.66	(2,171)	15.66
Units outstanding, December 31, 2006	423,855	$ 14.91	212,948	$ 15.41

Reconciliation of earnings per unit calculations

For the year ended December 31, 2006

	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic and diluted	$ (64,239)	44,141,688	$ (1.46)

For the calculation of the weighted average number of diluted units outstanding for 2006, all options, restricted and performance units, convertible debentures, warrants and exchangeable shares were excluded, as they were antidilutive to the calculation.

Reconciliation of earnings per unit calculations

For the year ended December 31, 2005

	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	$ 970	29,533,577	$ 0.03
Exchangeable shares / Non-controlling interest			
Options assumed exercised		1,277,405	
Units assumed purchased		(1,122,153)	
Diluted	$ 970	29,688,829	$ 0.03

For the calculation of the weighted average number of diluted units outstanding for 2005, 154,000 options, 301,000 warrants and 1,300,453 exchangeable shares were excluded, as they were antidilutive to the calculation.

Trust unit savings plan

In 2004, the Trust established a trust unit savings plan whereby the Trust will match an employee's contributions to the plan to a maximum of 9.0% of their salary. Both the employee's and the Trust's contributions were used to purchase trust units on the NYSE. During 2006 the Trust expensed approximately $313,000 (2005 - $25,000) relating to the Trust's contributions to the plan.

14. INCOME TAXES

The income tax provision is calculated by applying federal and provincial statutory tax rates to pre-tax earnings with adjustments as set out in the following table:

	2006	2005
Loss before income taxes and non-controlling interest	$ (121,850)	$ (16,292)
Combined federal and provincial income tax rate	34.50%	37.62%
Computed income tax reduction	(42,038)	(6,129)
Increase (decrease) resulting from:		
Interest component of trust distributions	(13,788)	(11,593)
Non-deductible royalties, net of ARTC	3,614	5,538
Resource allowance	(1,464)	(11,110)
Non-deductible items	1,418	3,536
Difference between U.S. and Canadian tax rates	(1,494)	(60)
Change in tax rates	(6,669)	1,201
Capital tax	341	1,456
Current tax	984	–
Other	1,521	(72)
	$ (57,575)	$ (17,233)

The components of the net future income tax liability at December 31 were as follows:

	2006	2005
Future income tax assets:		
Non-capital loss carry-forwards	$ 20,255	$ 21,573
Asset retirement obligations	8,969	8,177
Deferred financing charges	689	1,219
	$ 29,913	$ 30,969
Future income tax liabilities:		
Property, plant and equipment	66,343	131,266
Financial derivatives	3,910	–
Net future income tax liability	$ 40,340	$ 100,297

The tax rate applied to temporary difference is approximately 30% in 2006 (2005 – 34%) compared to the federal and provincial statutory rate of 34.5% (2005 – 37.62%). Non-capital loss carry-forwards expire from 2007 to 2015.

On December 21, 2006, the Federal Minister of Finance released draft legislation to implement proposals originally announced on October 31, 2006 relating to the taxation of certain distributions from certain trust and partnerships ("Trust Taxation Proposal"). Subject to the Trust Taxation Proposal, returns on capital are generally taxed as ordinary income in the hands of a unitholder who is resident in Canada for purposes of the Income Tax Act (Canada) ("Tax Act"). Pursuant to the Trust Taxation Proposal, commencing January 1, 2011 (provided the Trust only experiences "normal growth" and no "undue expansion" before then) certain distributions from the Trust which would otherwise have been taxed as ordinary income generally will be characterized as dividends in addition to being subject to tax at corporate rates at the trust level. Returns of capital generally are (and under the Trust Taxation Proposal will continue to be) tax-deferred for unitholders who are resident in Canada for purposes of the Tax Act (and reduce such unitholder's adjusted cost base in the trust unit for purposes of the Tax Act). Distributions whether of income or capital to a unitholder who is not resident in Canada for purposes of the Tax Act, or that is a partnership that is not a "Canadian Partnership" for purposes of the Tax Act, generally will be subject to Canadian withholding tax.

15. FINANCIAL INSTRUMENTS

The financial instruments recognized on the consolidated balance sheets include cash, accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, income taxes payable, bank indebtedness, convertible debentures, capital lease and financial derivatives. The fair values of financial instruments other than the financial derivatives, convertible debentures, capital lease and bank indebtedness approximate their carrying amounts due to the short-term nature of the instruments. The carrying value of bank indebtedness approximates its fair value due to floating interest terms; the fair value of the capital lease approximates its carrying value due to current rates for comparable terms of long-term debt. The financial derivative contracts are held at fair value with the gains and losses included within earnings for the period.

The Trust is exposed to fluctuations in commodity prices, foreign-currency exchange rates, interest rates and credit risk. The Trust manages its operations to minimize the exposure to these risks to the extent practical and, to a lesser extent, using derivative instruments and physical sales contracts. The Trust uses non-exchange traded forwards, swaps, options and physical deliver contracts to manage a portion of the Trust's commodity price risk. Management monitors the Trust's exposure to the above risks and regularly reviews its derivative activities and all outstanding positions.

(a) Commodity Price Risks

The Trust is exposed to fluctuations in natural gas and crude oil prices.

The Trust has entered into derivative financial instruments and fixed price physical contracts to minimize the exposure to fluctuations in the crude oil and natural gas prices. At December 31, 2006, the Trust had the following financial derivatives contracts outstanding:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Collars	Gas	7.50 by 12.00 (Cdn $/GJ)	7,500 GJ	January 1, 2007 – March 31, 2007
Collars	Gas	7.50 by 9.00 (Cdn $/GJ)	10,000 GJ	April 1, 2007 – October 31, 2007
Collars	Gas	8.00 by 12.00 (Cdn $/GJ)	10,000 GJ	Nov. 1, 2007 – March 31, 2008
Collars	Gas	8.00 by 15.70 (US $/mmbtu)	12,000 mmbtu	January 1, 2007 – March 31, 2007
Collars	Gas	7.50 by 11.20 (US $/mmbtu)	5,000 mmbtu	April 1, 2007 – October 31, 2007
Collars	Gas	7.50 by 11.10 (US $/mmbtu)	5,000 mmbtu	April 1, 2007 – October 31, 2007
Collars	Gas	8.00 by 16.40 (US $/mmbtu)	10,000 mmbtu	Nov. 1, 2007 – March 31, 2008
Collars	Oil	55.00 by 81.20 (US $/bbl)	1,000 bbl	January 1, 2007 – June 30, 2007
Collars	Oil	55.00 by 80.50 (US $/bbl)	1,000 bbl	January 1, 2007 – Dec. 31, 2007
Collars	Oil	55.00 by 80.50 (US $/bbl)	1,000 bbl	July 1, 2007 – Dec. 31, 2007
Collars	Oil	55.00 by 78.60 (US $/bbl)	500 bbl	January 1, 2007 – Dec. 31, 2007

Subsequent to December 31, 2006 the Trust entered into the following additional transactions:

- the Trust purchased US$11.20/mmbtu Nymex call options for 5,000 mmbtu/day for the April 1, 2007 to October 31, 2007 period to eliminate the ceiling on the $7.50 by $11.20 gas collar noted in the table above;
- the Trust sold 5,000 mmbtu/day, under fixed price Nymex contracts at US$7.555/mmbtu beginning April 1, 2007 to October 31, 2007; and
- the Trust entered into a costless collar covering 500 bbl/day of production for the period beginning January 1, 2008 to June 30, 2008 with a ceiling of US$75.25/bbl and a floor of US$55.00/bbl.

The fair market value of the financial derivatives at December 31, 2006 is estimated to be $10,775,000 (2005 - $415,000).

The Trust had the following fixed price physical contracts outstanding as at December 31, 2006:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Fixed sale	Gas	7.80 (Cdn $/GJ)	2,500 GJ	January 1, 2007 – March 31, 2007
Fixed purchase	Power (Alberta)	62.90 (Cdn $/Mwh)	72 Mwh	January 1, 2007 – Dec. 31, 2009

(b) Foreign Currency Exchange Risk

The Trust is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices. The Trust's U.S. subsidiary operates in a foreign currency which is translated to Canadian dollars as described in note 2. These operations are exposed to currency fluctuations.

(c) Credit Risk

A substantial portion of the Trust's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Trust's natural gas, crude oil and natural gas liquids are subject to an internal credit review to reduce the risk of non-payment. As at December 31, 2006 the Trust had recorded $1,060,000 (2005 - $1,504,000) as an allowance for doubtful accounts.

(d) Interest Rate Risk

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2006, the Trust had $187,695,000 (2005 - $95,450,000) of indebtedness bearing interest at floating rates. The balance of the Trust's indebtedness being the capital lease and the convertible debentures bear interest at fixed rates.

16. CHANGES IN NON-CASH WORKING CAPITAL

	2006	2005
Accounts receivable	$ 1,369	$ (9,684)
Prepaid expenses, deposits and other	(175)	(1,929)
Accounts payable and accrued liabilities	(18,891)	8,702
Foreign exchange on working capital	(3,935)	486
Changes in non-cash working capital	$ (21,632)	$ (2,425)
Changes in capital accounts payable	$ (7,645)	$ 3,733

During the year ended December 31, 2006 the Trust paid interest of $26,490,000 (2005 - $4,275,000) and taxes of $2,907,285 (2005 – $944,000).

17. COMMITMENTS

The Trust has commitments for the following payments over the next six years:

	2007	2008	2009	2010	2011	2012
Capital lease payments	$ 1,702	$ –	$ –	$ –	$ –	$ –
Imputed interest on capital lease	97	–	–	–	–	–
Office leases	1,162	1,086	1,087	1,171	1,171	1,171
	$ 2,961	$ 1,086	$ 1,087	$ 1,171	$ 1,171	$ 1,171

During 2006 total rental expense was $802,000 (2005 - $423,000).

18. CONTINGENCIES

At December 31, 2006 a claim in the amount of approximately US$3.9 million has been filed against the Trust related to its U.S. operations. The result of this claim is not determinable by the Trust. The Trust has also filed claims against the claimant.

Certain claims have been brought against the Trust in the ordinary course of business. In the opinion of management, all such claims, except as noted above, are adequately covered by insurance, or if not so covered, are not expected to materially affect the Trust's financial position.

19. SEGMENTED INFORMATION

The Trust has one operating segment that is divided amongst two geographical areas. The following is selected financial information from the two geographic areas.

	Year ended December 31, 2006	Year ended December 31, 2005
Revenue		
Canada	$ 156,859	$ 154,766
U.S.	87,549	3,331
	$ 244,408	$ 158,097
Property, plant and equipment		
Canada	$ 333,911	$ 469,503
U.S.	325,357	19,571
	$ 659,268	$ 489,074
Goodwill		
Canada	$ 76,256	$ 70,546
U.S.	–	–
	$ 76,256	$ 70,546

20. RELATED PARTIES

During 2006 the Trust paid $813,000 (2005 - $350,000) to Macon Resources Ltd. ("Macon"), a company 100% owned by the Chief Executive Officer of the Trust, for management services provided by the Chief Executive Officer and the previous Chief Financial Officer. The amounts have been recorded at the amounts agreed to by the related parties. At December 31, 2006 $nil (December 31, 2005 - $84,000) was payable by the Trust to Macon. During 2005, the Trust issued 400,000 trust unit options to Macon; the options have an exercise price of $23.96 per trust unit. The options have a 5-year life and vest over a 3-year period.

During 2006 the Trust entered into a farmout agreement with Petroflow Energy Inc. ("Petroflow"), a public oil and gas company, to fund 100% of the drilling and completion costs of the Oklahoma Asset's undeveloped lands. The Chief Executive Officer of the Trust owns, directly and indirectly, approximately 14% of the outstanding shares of Petroflow. As at December 31, 2006, the Trust had US$1.5 million of receivables from Petroflow including $47,000 (US$ $40,000) related to processing fees charged to Petroflow. The receivables relate to costs incurred by the Trust as a result of the operations of the properties. The balances due are expected to be settled as part of the asset purchase discussed in note 22.

A director and an officer of the Trust have working interests in certain of the Oklahoma Assets. Balances will be payable or receivable from these individuals as a result of the operations of these properties. At December 31, 2006 no amounts were payable or receivable from the officer. During 2006, an adjustment period on the Oklahoma Asset acquisition concluded. As a result of the adjustment payment and the receivable balance related to the working interests, as noted above, the Trust owes the director $744,000 (US$638,000).

21. RELATIONSHIP WITH JED OIL INC. AND JMG EXPLORATION INC.

On January 1, 2006, the Trust terminated a Technical Services Agreement with JED Oil Inc ("JED"), which had provided for services required to manage the Trust's field operations and governed the allocation of general and administrative expenses between the two entities. The Trust now manages its own management, development, exploitation, operations and general and administrative activities.

On September 28, 2006, the Trust terminated the existing farmout, joint services and an Agreement of Business Principles with JED. Concurrent with the termination of the agreements, the Trust settled all amounts owing to JED (December 31, 2005 - $15.2 million).

In September 2006, the Trust sold $44.0 million of petroleum and natural gas properties to JED in exchange for $30.9 million of petroleum and natural gas properties and the settlement of the $13.1 million balance due to JED Oil Inc. plus $1.4 million of post closing adjustments.

Previously, under an Agreement of Business Principles, properties acquired by the Trust were contract operated and drilled by JMG Exploration, Inc. ("JMG"), a publicly traded oil and gas exploration company, if they were exploration properties, and contract operated and drilled by JED, a publicly traded oil and gas development company, if they were development projects. Exploration of the properties was done by JMG, which paid 100% of the exploration costs to earn a 70% working interest in the properties. If JMG discovered commercially viable reserves on the exploration properties, the Trust had the right to purchase 80% of JMG's working interest in the properties at a fair value as determined by independent engineers. Had the Trust elected to have JED develop the properties, development would have been done by JED, which would pay 100% of the development costs to earn 70% of the interests of both JMG and the Trust. The Trust had a first right to purchase assets developed by JED.

22. SUBSEQUENT EVENTS

On February 21, 2007, the Trust entered into a purchase and sale agreement to purchase oil and natural gas properties from Petroflow for consideration of US$7.0 million. The purchase is subject to the fulfillment of certain conditions.

23. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements of Enterra Energy Trust ("the Trust") have been prepared in accordance with Canadian GAAP, which differs in some respects from U.S. GAAP. Any differences in accounting principles as they pertain to the consolidated financial statements are immaterial except as described below.

The application of U.S. GAAP would have the following effect on net income as reported for the year ended December 31, 2006 and 2005:

	Years Ended December 31, 2006	Years Ended December 31, 2005
Net earnings (loss) under Canadian GAAP	$ (64,239)	$ 970
Adjustments for U.S. GAAP		
Depletion expense (a)	(357,312)	(30,027)
Related income taxes	135,822	10,209
Gain on financial instruments (b)	1,289	154
Related income taxes	(441)	(57)
Reverse unit based compensation expense under Canadian GAAP (f)	3,229	–
Unit based compensation expense under US GAAP (f)	(935)	–
Non-controlling interest (e)	(36)	(29)
Interest accretion on convertible debentures under Canadian GAAP (h)	35	–
Gain on warrants (i)	1,215	
Foreign exchange (g)	848	–
Net loss under U.S. GAAP before cumulative effect of change in accounting policy under SFAS 123R (f)	(280,525)	(18,780)
Cumulative effect of change in accounting policy under SFAS 123R (f)	177	–
Net loss under U.S. GAAP	$ (280,348)	$ (18,780)
Other comprehensive (loss):		
Cumulative translation adjustment (g)	(1,082)	–
Other comprehensive income under U.S. GAAP	$ (281,430)	$ (18,780)
Net loss under U.S. GAAP	$ (280,348)	$ (18,780)
Change in redemption value of trust units (d)	441,983	115,090
Net earnings available to Unitholders under US GAAP after change in redemption value of trust units	$ 161,635	$ 96,310
Weighted average units for U.S. GAAP (000's)		
Basic	44,846	30,834
Diluted	46,316	30,989
Net (loss) per unit under U.S GAAP before cumulative effect of change in accounting policy under SFAS 123R (f)		
Basic and Diluted	$ (6.26)	$ (0.61)
Net (loss) per unit under U.S GAAP		
Basic and Diluted	$ (6.25)	$ (0.61)
Net earnings available to Unitholders per unit under U.S. GAAP after changes in redemption value of trust units:		
Basic	$ 3.60	$ 3.21
Diluted	$ 3.51	$ 3.11

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported at December 31, 2006 and 2005:

	December 31, 2006		December 31, 2005	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets:				
Current assets (b)	$ 55,166	$ 56,609	$ 50,713	$ 50,713
Property, plant and Equipment (a)	659,268	241,188	489,074	428,678
Goodwill (e)	76,256	49,832	70,546	49,832
Deferred finance charges	4,676	1,195	1,210	1,210
Future income tax (a)(b)	–	116,852	–	–
	$ 795,366	$ 465,676	$ 611,543	$ 530,433
Liabilities:				
Current liabilities (b) (f)	$ 243,849	$ 245,416	$ 163,110	$ 162,956
Asset retirement obligations	28,447	28,447	24,323	24,323
Future income tax (a)(b)	40,340	–	100,297	78,631
Capital lease	–	–	1,702	1,702
Convertible debentures (h)	78,974	76,787	–	–
	391,610	350,650	289,432	267,612
Non-controlling interest (e)	1,732	–	32,402	–
Mezzanine equity (d)	–	465,998	–	684,024
Unitholder's Equity				
Unitholders' capital (d)(e)(f)	635,134	–	373,761	–
Equity component of convertible Debentures (h)	1,327			
Warrants (i)	1,215	–	1,215	1,215
Contributed surplus (f)	3,195	–	573	573
Deficit	(240,777)	(352,054)	(85,840)	(422,991)
Cumulative translation adjustment (g)	1,930	–	–	–
Accumulated other comprehensive income (g)	–	1,082	–	–
	402,024	(350,972)	289,709	(421,203)
	$ 795,366	$ 465,676	$ 611,543	$ 530,433

(a) Property, Plant and Equipment

Under Canadian GAAP, the impairment test limits the capitalized costs of oil and natural gas assets to the discounted estimated future net revenue from proved and probable oil and natural gas reserves using forecast prices plus the costs of unproved properties less impairment. The discount rate used is a risk free interest rate.

Under U.S. GAAP, the full cost method of accounting for oil and natural gas activities requires the Trust to perform an impairment test using after-tax future net revenue from proved oil and natural gas reserves discounted at 10% plus the cost of unproved properties less impairment. The prices and costs used in the U.S. GAAP ceiling test are those in effect at the period end. Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion will differ in the year and subsequent years.

There were ceiling test impairments recognized under U.S. GAAP at December 31, 2006, 2005, 2004 and 2001. At December 31, 2006, the Trust recognized a U.S. GAAP ceiling test write-down of $76.9 million ($53.8 million after tax) in its Canadian cost center and $292.0 million ($175.2 million after tax) in its US cost center. At December 31, 2005, the Trust recognized a U.S. GAAP ceiling test write-down of $34.1 million ($22.5 million after tax) in its Canadian cost center and $3.0 million ($2.0 million after tax) in its US cost center. At December 31, 2004 the Trust recognized a U.S. GAAP ceiling test write-down of $10.0 million ($6.3 million after tax) and at December 31, 2001 the Trust recognized a write-down of $28.7 million ($17.5 million after tax) in its Canadian cost center (U.S. cost center did not exist prior to 2005).

Under Canadian GAAP, pursuant to EIC 151, property, plant and equipment increased as a result of the conversion of one class of exchangeable shares into trust units. Under U.S. GAAP, all classes of exchangeable shares are classified as mezzanine equity, valued at their redemption value and conversion of exchangeable shares does not result in an increase in property, plant and equipment. This GAAP difference in the valuation of property, plant and equipment results in an increase in depletion expense during the periods presented for Canadian GAAP as compared with U.S. GAAP (see note e).

These differences in the carrying value of property, plant and equipment result in depletion expense being different under U.S. GAAP as compared with Canadian GAAP. For the year ended December 31, 2006 depletion under U.S. GAAP was lower by $12.6 million ($8.3 million after tax) and, including the ceiling test write downs under U.S. GAAP, was higher by $314.5 million ($220.7 million after tax) for the year ended December 31, 2006 (2005 - $30.0 million and $19.8 million after tax).

(b) Financial Instruments and Marketing Contracts

Under Canadian GAAP, the Trust's physical delivery contracts are not considered financial instruments and are not measured at fair value on the balance sheet. For US GAAP, the Trust did not formally document and designate these outstanding contracts as physical sales contracts, therefore the contracts are re-valued each period end to estimated fair value (mark-to-market). At December 31, 2006, the Trust had physical delivery contracts in place valued at $1.4 million which increased earnings under US GAAP by $1.4 million ($0.8 million after tax) for 2006. At December 31, 2005, under Canadian GAAP the physical sales contracts recorded on the balance sheet were at the amortized cost of $1.4 million as a result of the contracts being acquired with High Point. At December 31, 2005, the fair value of the contracts was $1.3 million resulting in a reduction to the marketing liability recorded on the balance sheet and an increase in earnings under US GAAP of $0.2 million ($0.1 million after tax).

(c) Earnings

Under U.S. GAAP, interest and amortization of deferred financing charges would be presented in the non-operating section of the statement of earnings.

(d) Unitholder's Mezzanine Equity

Under Canadian GAAP, the trust units are considered to be permanent equity and are classified as unitholders' capital. A U.S. GAAP difference exists due to the redemption feature attached to each trust unit. The trust units are redeemable at the option of the holder based on the lesser of 90% of the average market trading price of the trust units for the 10 trading days after the date of redemption or the closing market price of the trust units on the date of redemption. Trust units can be redeemed to a cash limit of $100,000 per year or a greater limit at the discretion of the Trust. Redemptions in excess of the cash limit shall be satisfied first by the issuance of notes by a subsidiary of the Trust and second by issuance of promissory notes by the Trust.

The redemption feature causes the trust units to be classified as mezzanine equity under U.S. GAAP. Mezzanine equity is valued at an amount equal to the redemption value of the trust units at the balance sheet date. Included in the redemption value of the trust units is the redemption value of the exchangeable shares as if all exchangeable shares had previously been converted into trust units. Any increase or decrease in the redemption value during a period is charged to the deficit.

As at December 31, 2006, unitholders' capital was reduced by $635.1 million and non-controlling interest was reduced by $1.7 million (December 31, 2005 - $ 373.8 million and $32.4 million, respectively) and the redemption value of the trust units and exchangeable units of $466.0 million (December 31, 2005 - $684.0 million) was recorded as mezzanine equity. The change in the redemption value of the trust units and exchangeable units is recorded as a reduction or increase to the deficit. For the year ended December 31, 2006 the deficit was reduced by $442.0 million (year ended December 31, 2005 – $115.1 million).

(e) Exchangeable Securities Issued by Subsidiaries of Income Trusts Pursuant to EIC-151

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. EIC-151 requires that the shares be nontransferable to be classified as equity. The Trust's exchangeable shares are transferable and, in accordance with EIC-151, have been reclassified to non-controlling interest on the Canadian GAAP consolidated balance sheets.

Since a portion of Enterra's exchangeable shares were not initially recorded at fair value, subsequent exchanges for Trust Units are measured at the fair value of the Trust Units issued. The excess of fair values over book values on the exchange are recorded as additions to property, plant and equipment and goodwill. In addition, non-controlling interest is reflected as a reduction of such earnings in the Trust's consolidated statements of earnings.

The application of EIC-151 causes several differences with U.S. GAAP. As at December 31, 2006, property, plant and equipment increased by $1.8 million (December 31, 2005 - $1.4 million), goodwill increased by $26.4 million (December 31, 2005 - $20.7 million, December 31, 2004 - $19.3 million), future income tax liability increased by $0.7 million (December 31, 2005 - $0.6 million, December 31), unitholder capital increased by $27.9 million (December 31, 2005 - $21.9 million, December 31), the deficit increased by $0.4 million (December 31, 2005 - $0.4 million).

(f) Unit-based Compensation

Effective January 1, 2006, the Trust adopted SFAS No. 123 (revised 2004), "Share-Based Payment", ("SFAS 123R") which is a revision of SFAS No. 123, "Accounting for Stock-based Compensation". SFAS 123R requires all unit-based payments to employees, including grants of employee unit options, be recognized in the financial statements based on their fair values. Liability classified awards, such as the Trust's restricted units, performance units and unit options are re-measured to fair value at each balance sheet date until the award is settled rather than being treated as an equity classified award on the grant date as required under SFAS 123 and Canadian GAAP. The Trust has adopted this standard by applying the modified prospective method. As a result of the adoption of SFAS 123R, the Trust has increased current liabilities by $0.6 million, which represents the fair value of all outstanding unit options at January 1, 2006, in proportion to the requisite service period rendered to that date. In addition, contributed surplus has been reduced by $0.5 million and net earnings have been increased by $0.2 million representing previously recognized compensation cost for all outstanding unit options and a credit to record the cumulative effect of a change in accounting principle. Changes in fair value between periods are charged or credited to earnings with a corresponding change in current liabilities. As at December 31, 2006, the fair value recognized within current liabilities was $0.9 million.

The Trust issues all units upon the exercise of all unit options, restricted units and performance units out of treasury.

For the years ended December 31, 2006 and 2005, the Trust recorded the following unit-based compensation (in thousands):

	Restricted and performance units		Unit options		Total
	Years ended December 31,		Years ended December 31,		Years ended December 31,
	2006	2005	2006	2005	2006	2006
General and administrative expenses	$ 1,280	–	$ (345)	$ 731	$ 935	$ 731

A summary of the status of the unvested options, restricted units and performance units as of December 31, 2006, and changes during the year there-ended, is presented below:

	Number of unvested options	Weighted average grant date fair value	Number of unvested restricted units	Weighted average grant date fair value	Number of unvested performance units	Weighted average grant date fair value
Unvested, January 1, 2006	1,361,500	$ 2.35	–	$ –	$ –	$ –
Granted	752,000	1.07	479,466	14.90	215,119	15.06
Vested	(384,669)	2.12	(44,375)	15.08	–	–
Forfeited	(502,497)	2.27	(11,236)	15.66	(2,171)	15.66
Unvested, December 31, 2006	1,226,334	$ 1.62	423,855	$ 14.91	212,948	$ 15.41

The following table provides information related to unit option activity during the year ended December 31, 2006:

	Number of unit options	Weighted average exercise price	Weighted average contract life	Aggregate intrinsic value (a) (000's)
Options outstanding, January 1, 2006	1,431,405	$ 22.31		
Options granted	752,000	15.70		
Options exercised	(99,905)	14.00		$ 50
Options forfeited	(602,500)	23,62		
Options outstanding, December 31, 2006	1,481,000	$ 20.28	3.89	–
Options expected to vest, December 31, 2006	1,332,900	$ 20.28	3.89	–
Options exerciseable, December 31, 2006	254,666	$ 23.85	3.47	–

	Number of units	Weighted average contract life	Aggregate intrinsic value (a) (000's)
Restricted units outstanding, January 1, 2006	–		
Restricted units granted	479,466		
Restricted units exercised	(44,375)		$ 400
Restricted units forfeited	(11,236)		
Restricted units outstanding, December 31, 2006	423,855	2.03	$ 4,435
Restricted units expected to vest, December 31, 2006	381,470	2.03	$ 3,992
Restricted units exerciseable, December 31, 2006	–	–	–

	Number of units	Weighted average contract life	Aggregate intrinsic value (a) (000's)
Performance units outstanding, January 1, 2006	–		
Performance units granted	215,119		
Performance units exercised	–		
Performance units forfeited	(2,171)		
Performance units outstanding, December 31, 2006	212,948	1.38	–
Performance units expected to vest, December 31, 2006	191,653	1.38	–
Performance units exerciseable, December 31, 2006	–	–	–

The intrinsic value of a unit option is the amount by which the current market value of the underlying unit exceeds the exercise price of the option. The intrinsic value of a restricted unit is the current market value of the underlying unit. The intrinsic value of a performance unit is the market value of the underlying unit multiplied by the performance factor at year end.

As of December 31, 2006, there was $0.5 million of total unrecognized compensation cost related to unvested unit options. The cost is expected to be recognized over a weighted average period of 1.9 years.

As of December 31, 2006, there was $2.7 million of unrecognized compensation cost related to unvested restricted units. The cost is expected to be recognized over a weighted average period of 2.0 years.

As of December 31, 2006, there was $nil million of unrecognized compensation cost related to unvested performance units.

(g) Cumulative Translation Adjustment and Other Comprehensive Income

The Trust's U.S. oil and natural gas properties are considered to be self sustaining. Under Canadian GAAP gains or losses resulting from the translation of the division to Canadian dollars are included in the cumulative translation account in unitholders' equity. Under U.S. GAAP gains or losses resulting from the translation of the division to Canadian dollars are included in the other comprehensive income. Under Canadian GAAP, a portion of the cumulative translation adjustment is recognized in income as the investment in the foreign operations is reduced. Under U.S. GAAP, the cumulative translation adjustment is recognized in income upon disposition of the segment. For the year ended December 31, 2006, $848,000 of the cumulative translation adjustment was recognized as a foreign exchange loss under Canadian GAAP.

(h) Convertible Debentures

In November 2006, the Trust issued convertible debentures. Under Canadian GAAP, the Trust's convertible debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity. Under U.S. GAAP, the convertible debentures in their entirety are classified as debt. Under Canadian GAAP the issue costs allocated to the debt portion of the convertible debentures are classified as a deferred finance charge. Under U.S. GAAP, the issued costs allocated to the debt portion of the convertible debentures are netted against the convertible debenture. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component is recorded in the consolidated statements of earnings (loss) with a corresponding credit to the convertible debenture liability balance to accrete that balance to the full principal due on maturity. This non-cash interest expense recorded under Canadian GAAP is not recorded under U.S. GAAP.

(i) Warrants

Under Canadian GAAP, the Trust accounts for warrants as a component of equity. Under U.S. GAAP, the warrants are considered a liability therefore they are carried at estimated fair value with changes in the estimated fair value recorded in earnings. As at December 31, 2006, the estimated fair value of the warrants were $nil resulting in an increase of $1.2 million to 2006 earnings under U.S. GAAP.

(j) Additional Disclosure Under U.S. GAAP

	December 31, 2006	December 31, 2005
Components of accounts receivable		
Trade	$ 17,301	$ 18,367
Accruals	22,736	18,440
Allowance for doubtful accounts	(1,057)	(1,504)
	$ 38,980	$ 35,303
Components of prepaid expenses		
Prepaid expenses	$ 1,772	$ 1,025
Funds on deposit	1,477	2,027
	$ 3,249	$ 3,052
Components of accounts payable		
Accounts payable	$ 17,402	$ 28,306
Accrued liabilities	28,681	8,042
	$ 46,083	$ 36,348

(k) Select Pro Forma Financial Information for High Point Acquisition (unaudited)

As shown in note 4 of the Canadian GAAP financial statements, the Trust completed the acquisition of High Point. Under U.S. GAAP, select pro forma financial information is disclosed as if the acquisition had occurred on January 1, 2005 instead of the actual closing of August 17, 2005. The following table shows the pro forma U.S. GAAP select financial information for the acquisition of High Point.

	December 31, 2005 (unaudited)
Revenue	$ 191,247
Net loss before change in redemption value of trust units	$ (18,804)
Per unit - basic	$ (0.52)
Per unit - diluted	$ (0.52)
Net earnings (loss)	$ 97,977
Per unit - basic	$ 2.69
Per unit - diluted	$ 2.68

(l) New Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation ("FIN 48") No. 48, Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109. Fin 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, Accounting for Taxes. Fin 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. Fin 48 is effective for fiscal years beginning after December 15, 2006. The Trust has not yet determined the impact of the financial position, results of operations or cashflows from Fin 48.

In February 2006, the FASB issued SFAS No. 155, 'Accounting for Certain Hybrid Financial Instruments - an amendment of FASB Statements No. 133 and 140' ("SFAS 155"). SFAS 155 simplifies the accounting for certain hybrid financial instruments under SFAS 133 by permitting fair value remeasurement for financial instruments containing an embedded derivative that otherwise would require separation of the derivative from the financial instrument. SFAS 155 is effective for all financial instruments acquired, issued or subject to a remeasurement event occurring in fiscal years beginning after September 15, 2006. The Trust does not expect that SFAS 155 will have a material impact on the financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, 'Fair Value Measurements' ("SFAS 157"). SFAS 157 defines fair value, establishes a framework for measuring fair value under GAAP and to expands disclosures about fair value measurements. The statement is effective for fair value measures already required or permitted by other standards for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The Trust has not yet determined the impact of the financial position, results of operations or cashflows from SFAS 157.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115" ("SFAS 159"). This pronouncement permits entities to use the fair value method to measure certain financial assets and liabilities by electing an irrevocable option to use the fair value method at specified election dates. After election of the option, subsequent changes in fair value would result in the recognition of unrealized gains or losses as period costs during the period the change occurred. SFAS 159 becomes effective as of the beginning of the first fiscal year that begins after November 15, 2007, with early adoption permitted. However, entities may not retroactively apply the provisions of SFAS 159 to fiscal years preceding the date of adoption. The Trust is currently reviewing the impact SFAS 159 may have on the financial position, results of operations or cashflows.

Enterra Energy Trust

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Stock Exchange Listings

NYSE (symbol: ENT)
TSX (symbol: ENT.UN)

Board of Directors

R.H. (Joseph) Vidal
Peter Carpenter
Roger Giovanetto
W. Cobb (Chip) Hazelrig
Norman W.G. Wallace
E. Keith Conrad

Senior Management

E. Keith Conrad,
President & Chief Executive Officer

Victor Roskey,
Senior Vice President & Chief Financial Officer

John F. Reader,
Senior Vice President Corporate Development

James (Jim) Tyndall,
Senior Vice President Operations &
Chief Operating Officer

Kim Booth,
Vice President & Chief Operating Officer,
U.S. Operations

Investor Relations Website

www.enterraenergy.com

Annual General and Special Meeting

June 14, 2007, 10 a.m. MT
Metropolitan Centre
Grand Lecture Theatre
333 – 4th Avenue S.W.
Calgary, AB T2P 0H9

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ENERGY TRUST

Enterra

2006 ANNUAL REPORT

CORPORATE PROFILE

ENTERRA ENERGY TRUST is a conventional oil and gas trust that acquires, operates and exploits petroleum and natural gas assets principally in Alberta and British Columbia, Canada, and in Oklahoma, U.S.A. Our portfolio of crude oil, natural gas liquids and natural gas interests is geographically diversified and is balanced between natural gas and liquids production.

The company has head offices in Calgary, Alberta, and Carney, Oklahoma. Our trust units are listed on the Toronto Stock Exchange (ENT.UN) and the New York Stock Exchange (ENT).

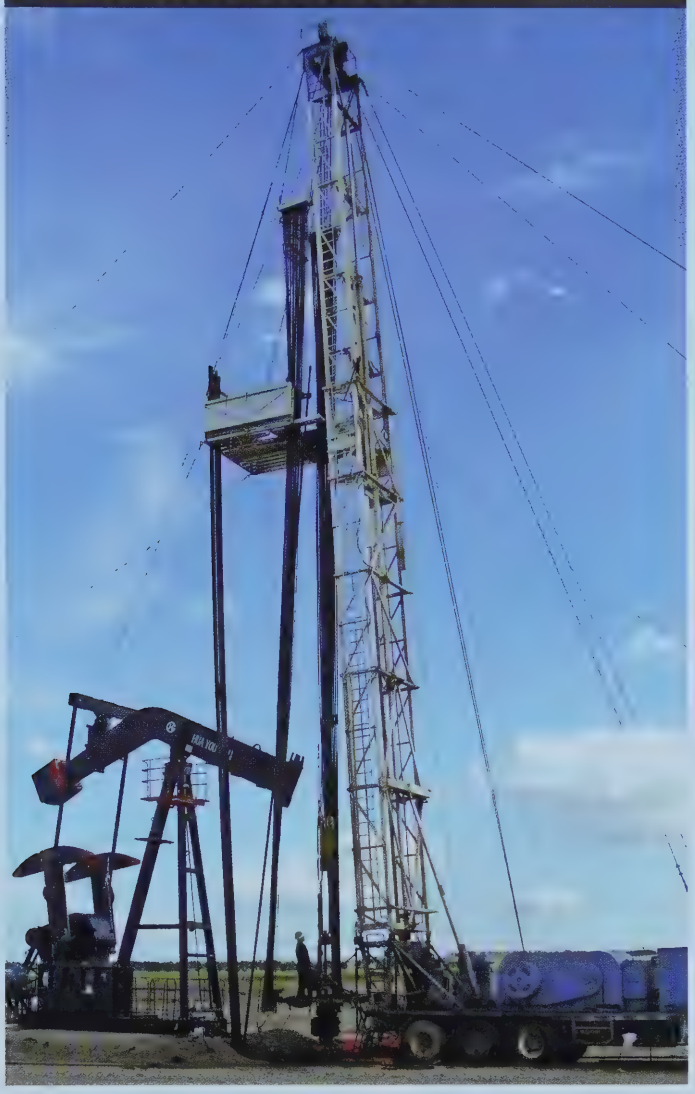
Visit www.enterraenergy.com for more information.

Forward-Looking Statements

This Annual Report contains forward-looking statements relating to expected future events and financial and operating results of the Trust that involve risks and uncertainties. Please refer to the Management's Discussion and Analysis for a caution to the reader on the reliance of such statements. Readers are also directed to the "Risk Factors" section in the Trust's Annual Information Form (which can be found on www.sedar.com) for a full disclosure of the risks and uncertainties relating to the forward-looking statements.

The Trust's corporate governance practices differ from those required of domestic companies under NYSE listing standards. A summary of these differences is stated in the Trust's Form 40-F, which can be found at www.enterraenergy.com.

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Investing in Stability, Growth and Diversification

Enterra's purpose is to generate strong returns for our unitholders through a combination of sustainable cash distributions and capital appreciation. Our intent is to maintain and to strive to increase the reserves, production and funds from operations that underpin every trust unit. To achieve our goals the Trust will adhere to a three-pronged strategy:

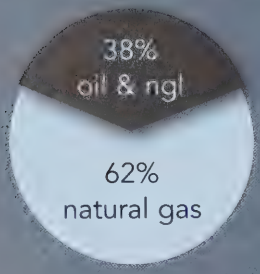
Organic Growth: We will economically sustain our production and reserves by reinvesting cash flow in lower-risk projects within existing core areas of Enterra's asset base.

Accretive Acquisitions: We will pursue acquisitions of oil and gas assets that will consolidate existing core areas, or will create new core areas with organic growth or strategic partnership potential.

Strategic Partnerships: Through our partnerships, we will exploit high-return opportunities that increase reserves and production and preserve the potential for Enterra to acquire the partner's interest in the future. Such partnerships allow us to move faster, manage risk more effectively, and to access technical expertise and services that would otherwise be in scarce supply.

ENTERRA INTENTIONALLY MAINTAINS A BALANCED PORTFOLIO WITH RESPECT TO:

Diversified Commodity Mix
OIL VERSUS GAS



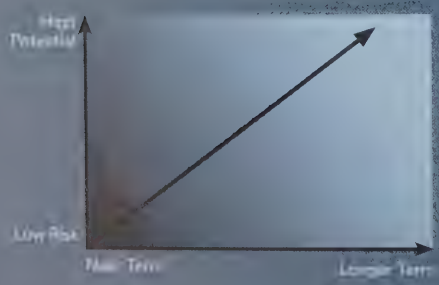
(Year end exit production)

Geographic Diversity
CANADA VERSUS UNITED STATES

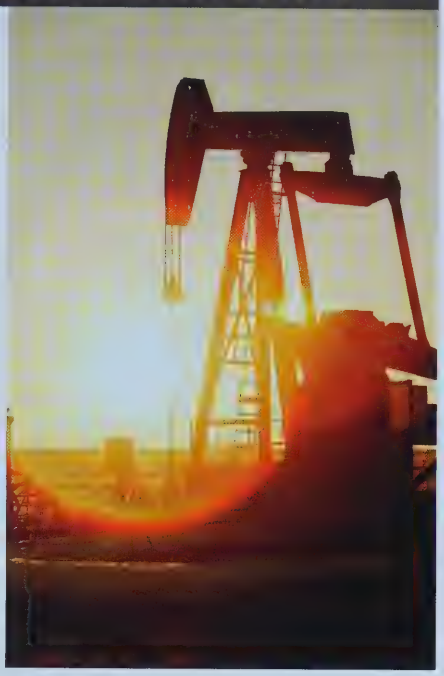


(Year end exit production)

Balanced Time Frame and Risk
NEAR TERM, LOW RISK VERSUS
LONGER TERM, HIGH POTENTIAL



2006 KEY ACCOMPLISHMENTS



Stronger Balance Sheet:

- Completed a $178 million bought deal financing of trust units and convertible debentures and a $200 million revolving term and operating credit facilities arrangement.

Growth-oriented Acquisition in Oklahoma:

- Acquired oil and natural gas producing assets, contributing production of approximately 5,000 boe/day to Enterra's 2006 exit rate, which broadened and diversified Enterra's reserves and undeveloped land base.

Major Property Consolidation in Canada:

- Closed a property swap valued at $44.1 million with JED Oil Inc. which allows Enterra to control the level of risk and pace of development on our properties and enhances organic growth opportunities.

Restructured Organization:

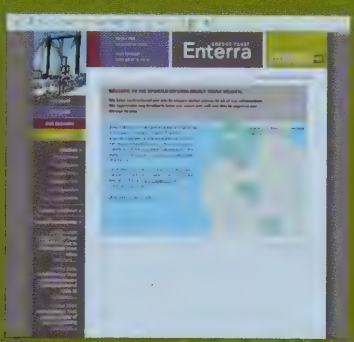
- Developed a full service employee base from field to finance as part of developing a firm foundation for the future.
- New executive and board members have established forward-looking strategies, processes and governance to reinforce Enterra's performance going forward.

Successful Results from New Strategic Partnership:

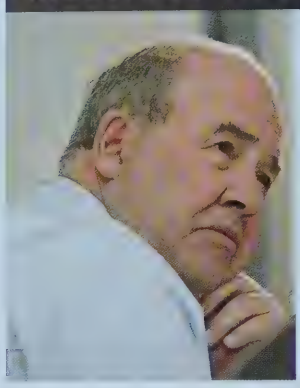
- Established a new strategic partnership with Petroflow Energy Ltd. on the Oklahoma assets which insulates Enterra from drilling risk while allowing us to retain significant ownership of all assets as they are developed.
- Enterra continues to operate all existing and new production, and to acquire new undeveloped lands in this key growth area.

Improved Investor Relations Website

- Upgraded website for easier navigation and accessibility to information.
- The new site includes an expanded Investors section, with NYSE and TSX quotes and charts, Tax Information, Frequently Asked Questions and a convenient subscription option to receive press release alerts by email.



MESSAGE FROM THE PRESIDENT



Dear Fellow Unitholders:

For Enterra Energy Trust, 2006 marked the culmination of a profound transition that began in mid-2005. While we faced a number of challenging situations that required difficult but necessary decisions, the last major building block was laid with the closing of a major refinancing in November, 2006. As a result, Enterra now stands revitalized, on a firm foundation, and poised to pursue opportunities for enhanced stability and growth.

The strategy we undertook 18 months ago emphasized five main objectives:

- Solid Production Base
- Strong Balance Sheet
- Strategic Relationships
- Superior Staff; and
- Sustainable Distributions – our ultimate goal

Since then, we have focused all of our efforts on these goals in order to build a strong foundation for the pursuit of our future business. Let me outline our achievements in each area.

Solid Production Base

Over the past year we have diversified and grown our production base. In April 2006, Enterra completed an acquisition of oil and natural gas producing assets located in the State of Oklahoma. The transaction significantly broadened our reserve base and increased our portfolio of undeveloped lands and opportunities. In addition, The Oklahoma acquisition added approximately 5,700 boe/day of production by April 2006, helping bring Enterra's total 2006 exit production rate to 12,442 boe/day, a 34% increase over 2005. This major step has significantly shifted Enterra from a regional player to one with a much broader view. In addition, 45 successful conventional wells were drilled on Trust lands in 2006 (13.1 net to Enterra). Our average production for 2006 increased 60% over the prior year, and our Reserve Life Index increased to 6.0 years.

Strong Balance Sheet

Further to our promise to strengthen Enterra's balance sheet before year end, in November 2006 we completed a significant financing and repaid all indebtedness under outstanding bridge facilities. Enterra's improved financial position increases our flexibility to reinvest in our business and allows us to pursue more organic growth opportunities. These efforts have provided the stability and financial means to aggressively pursue our long term strategy into 2007 and beyond.

Strategic Relationships

Enterra has had the benefit of venturing with industry partners who give us access to projects that otherwise may not be available due to the nature, scale, degree of risk involved or expertise required to capitalize on the opportunity. Enterra established an agreement with Petroflow Energy Ltd. ("Petroflow") on our Oklahoma assets under which Petroflow funds 100% of the drilling and completion costs and earns a 70% working interest, with the additional 30% being retained by the Trust. This fascinating and technically challenging resource play in Oklahoma incorporates multi-leg horizontal



- 60% increase in average production
- 55% increase in revenue
- 42% increase in reserves
- 34% increase in exit production
- 22% increase in net undeveloped land
- 7% increase in RLI
- 3% decrease in operating cost per boe

drilling and a unique strategy of reservoir dewatering. Petroflow's efforts help to insulate Enterra from higher risk exploitation and allow us to capitalize, as the opportunity progresses and matures, on the geological and operational knowledge gained from aligning with a management team and individuals who possess specific experience and proven skills.

Also in 2006 the Trust ended its multi-year relationship with JED Oil Inc. Since 2004 JED Oil had drilled approximately 40 wells on Trust lands, adding important reserves and production to Enterra's Canadian properties. An exchange of assets achieved a consolidation of Enterra's operations in Canada, which allows us to better control the pace of development on properties already owned by Enterra, and enhances our efforts to pursue organic growth opportunities.

Superior Staff

Critical to our success has been the tremendous efforts of our excellent staff in every facet of our business. In late 2005 Enterra had only three employees and relied on outsourcing most business functions. At present we have 112 employees providing the full range of skills necessary to efficiently run the affairs of the Trust and to provide the basis for its future. These skills span the business and include field operators, land and legal administrators, professionals in accounting and finance, engineering, exploration, and business development as well as senior level executives. Personnel additions in 2006 included the executive appointments of Victor Roskey as Senior Vice President and Chief Financial Officer, James Tyndall as Senior Vice President Operations and Chief Operating Officer, Kim Booth as Vice President and Chief Operating Officer, U.S. Operations, and the promotion of John Reader to Senior Vice President Corporate Development. This fine team was assembled at a time of extreme competitiveness in the North American oil and gas industry.

Sustainable Distributions

All of the efforts described above and throughout this Annual Report are focused on advancing our primary



strategy and purpose: developing a business foundation that will enable sustainable distributions and the potential for growth. In 2006 Enterra distributed over $90 million in cash to unitholders. Like all oil and gas companies, Enterra faces a regular decline in its base production portfolio – a decline that must be replaced by drilling and acquisitions. In recognition of this essential undertaking, we made the difficult but responsible decision in July 2006 to revise our distribution policy and implement a target payout ratio range of 60% to 70% of funds from operations, reduced from the previous 90% to 100%. The new policy required a distribution reduction from US$0.18/unit to US$0.12/unit. Adopting this sensible payout ratio increases our financial flexibility and will ensure that cash is available to manage our base production portfolio decline and to develop Enterra's inventory of drilling and development opportunities.

In the latter half of 2006, a significant pull back in oil and natural gas prices reduced the funds available for both distributions and capital programs. It is important for unitholders to note that such a dramatic change in commodity prices has a disproportionate impact on our funds available for distribution and reinvestment due to the many fixed costs embedded in the petroleum business that do not change with product prices, and the variable costs that lag the changes. This required us to again amend our distributions in early 2007 to US$0.06/unit. Be assured that your management and Board of Directors do not take decisions to change our distribution level lightly; however, there was no real alternative to this action since a failure to reinvest in our production base would completely compromise the future and sustainability of our business.

Financial Results for 2006

At the end of a year of transformation, Enterra reported significant advances in many important areas including year-over-year revenue, production, reserves, funds from operations and undeveloped land. At the same time, we have reduced unit operating costs and finding, development and acquisition costs. However, we also recognize that some parts of our cost structure and one-time expenses for 2006 are too high.

As part of our restructuring, Enterra incurred $28 million of non-recurring financing costs in 2006. These fees relate to our critical efforts to establish a firm financial footing for the Trust, but negatively impacted our fourth quarter results.

In our year end financials for 2006 we report a $66 million ceiling test write-down. This results primarily from a simultaneous decrease in

forecast commodity prices and an increase in forecast operating costs. These factors negatively impacted the evaluation of our reserves and caused us to lower the carrying costs of some of our undeveloped lands. While we cannot impact the future of commodity prices (although we do hedge our production and this is not taken into account during reserve analysis), we believe that industry costs will fall in 2007 and we have increased our internal focus on efficiency and portfolio rationalization. It is important for unitholders to know that, with minor exceptions, our assets continue to perform as expected and that this book write-down does not imply a significant change to our anticipated future production.

A further unexpected and profound challenge faced by all Canadian income trusts was the announcement that the Canadian government intends to tax distributions starting in 2011 and, more importantly, to restrict the ability of trusts to grow. While these changes are being debated and legislation has not yet been enacted, the impact on the sector has been negative.

Enterra's management and Board of Directors are assessing a wide range of alternatives that will allow us to continue to pursue our business goals. Like some of our peers, Enterra may consider conversion to a corporate structure at some point in the future. We will await further clarity from the government regarding these changes before making a final decision. However, our priority is to ensure that the interests of our unitholders are secured with a business model that continues to be founded on regular and sustained distributions to unitholders.

Outlook for 2007

While 2006 has been a challenging year, we believe the actions we have taken position us well for the future.

The volatility created by uncertain energy prices, correspondingly volatile financial markets, and proposed income trust tax legislation warrants a conservative approach, and this is the path we have taken. By retaining our cash, we are confident that we can fund our capital program without external sources of funding, a situation that could become a competitive advantage as many of our peers may find themselves financially constrained.

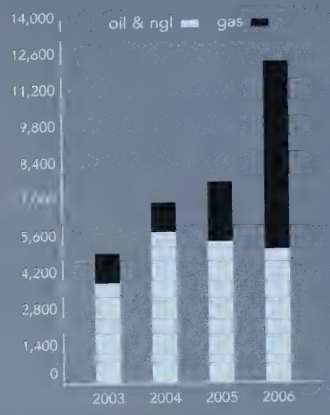
We remain optimistic about the long term strength of energy prices. Our actions in 2006 and early 2007 will allow us to make critical reinvestments to ensure our continued stability and growth and to continue to execute our business plan with the goal of generating long term value.

In closing, I wish to thank our executives and employees for their tremendous work and dedication in 2006 and for their continued commitment in 2007. Our Board of Directors has been crucial in supporting our goals and in providing guidance to help build the foundations for the future of Enterra. Regardless of the challenges ahead, we feel that we have the skills, assets and tools to address them and to deliver a sustainable future and continued growth for every unitholder.

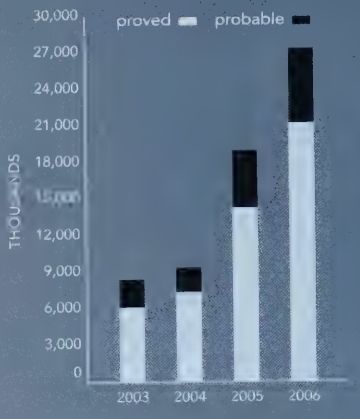


E. Keith Conrad
PRESIDENT & CEO

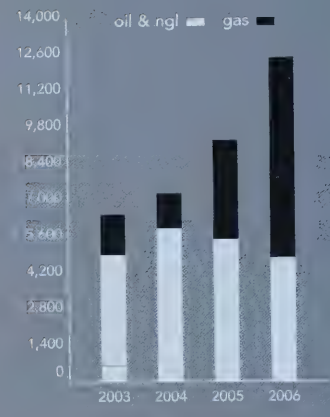
2006 HIGHLIGHTS



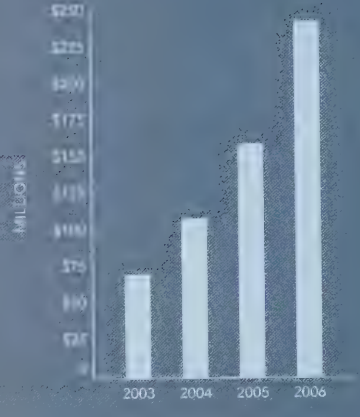
AVERAGE PRODUCTION (BOE/DAY)
2003-2006



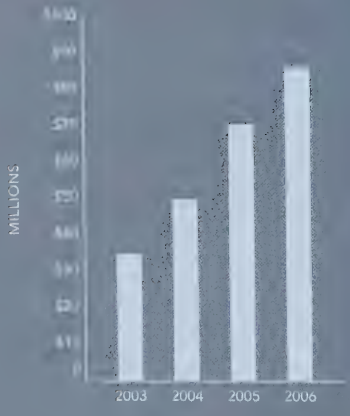
RESERVES (MBOE)
2003-2006



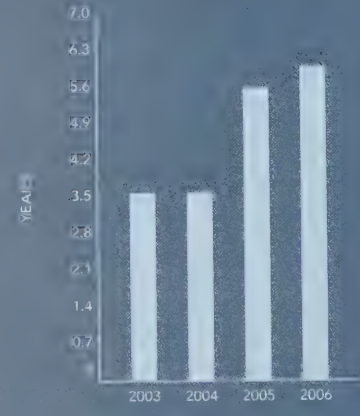
EXIT PRODUCTION (BOE/DAY)
2003-2006



REVENUE (CDN $)
2003-2006



FUNDS FROM OPERATIONS (CDN $)
2003-2006



RESERVE LIFE INDEX
(Proven Plus Probable)
2003-2006

2006 SUMMARY

For the Year Ended December 31, 2006, 2005 and 2004	2006	2005	2004
FINANCIAL			
Revenue	$ 244,408	$ 158,097	$ 108,293
Funds from operations	$ 86,117	$ 70,545	$ 50,242
Per unit	$ 1.95	$ 2.39	$ 2.23
Cash provided by operating activities	$ 64,485	$ 68,120	$ 42,345
Per unit	$ 1.46	$ 2.31	$ 1.88
Net earnings (loss)	$ (64,239)	$ 970	$ 14,027
Per unit	$ (1.46)	$ 0.03	$ 0.62
Total assets	$ 795,366	$ 611,543	$ 221,128
Total bank debt, note payable and capital lease obligations	$ 189,856	$ 102,101	$ 47,315
Convertible debentures	$ 78,974	$ –	$ –
Unitholders' equity	$ 402,024	$ 289,709	$ 114,971
SHARES AND UNITS OUTSTANDING			
Weighted average number of units outstanding in year	44,141,688	29,533,577	22,518,373
Number of units outstanding at the end of the year	56,097,875	36,504,416	25,426,800
Number of exchangeable shares outstanding at the end of the year	83,057	1,744,104	553,214
PRODUCTION			
Average daily production			
Oil production (bbls/day)	5,126	5,453	5,821
Gas production (mcf/day)	43,358	13,729	6,817
Total production (boe/day)	12,352	7,741	6,957
Exit production			
Oil production (bbls/day)	4,758	5,476	5,905
Gas production (mcf/day)	46,105	22,836	8,118
Total production (boe/day)	12,442	9,282	7,258
Average field price per year			
Oil ($/bbl)	$ 62.13	$ 58.11	$ 43.00
Gas ($/mcf)	$ 7.53	$ 8.40	$ 6.69
PER BOE INFORMATION			
Revenue	$ 51.82	$ 55.83	$ 42.53
Financial derivative gain (loss) and other revenue	2.40	0.13	(1.25)
Royalties	10.71	12.77	9.63
Production expenses	11.17	11.55	9.25
Operating netbacks	32.34	31.64	22.40
General and administrative	4.52	3.66	1.75
Interest	5.93	1.67	0.87
Corporate netbacks	21.89	26.31	19.78
Amortization of deferred charges	2.60	0.01	0.01
Financing fees	1.21	–	–
Depletion and depreciation (including ceiling test impairments)	44.68	29.05	14.13
Goodwill impairment	–	3.27	–
Foreign exchange	0.42	(0.25)	–
Earnings (loss) from operations	(27.02)	(5.78)	5.64
Income tax	(12.77)	(6.10)	0.07
Net earnings (loss) before non-controlling interest per boe	(14.25)	0.32	5.57
Non-controlling interest	(0.01)	(0.01)	0.16
Net earnings per boe	$ (14.24)	$ 0.33	$ 5.41

	3 year average	2006	2005	2004
RESERVES				
Proved reserves (mboe)		21,218	14,295	7,385
Probable reserves (mboe)		6,140	4,737	2,024
Total reserves (mboe)		27,358	19,032	9,409
Finding costs (excluding FDC)				
Proved reserves	$ 34.05	$ 32.24	$ 43.11	$ 17.38
P+P reserves	$ 29.14	$ 27.89	$ 33.71	$ 18.68
Operating recycle ratio	1.09	1.07	0.93	1.27

OPERATIONAL SUMMARY



Operational Overview
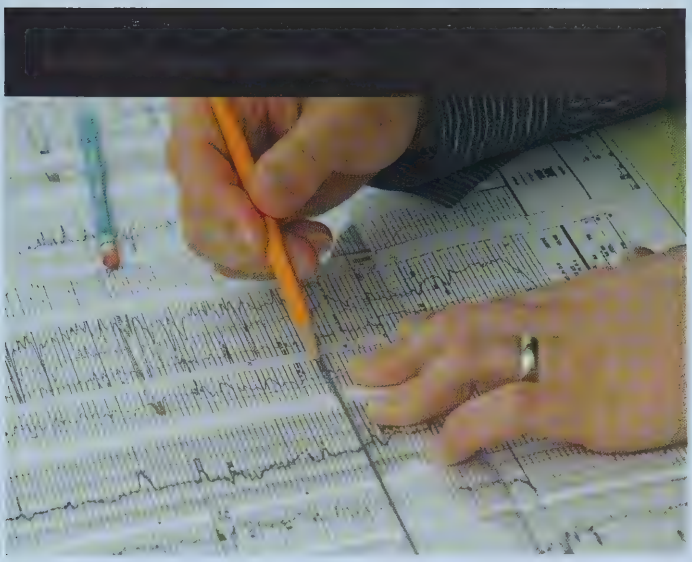
Enterra maintains a diverse portfolio of operations in Alberta and British Columbia in Canada, and in Oklahoma and Wyoming in the United States. The majority of this production is mature and stable in nature, and provides predictable, well-defined product and cash flow streams. The management of these assets and the minimization of natural declines are part of our day to day activities.

In alignment with one of our key strategies, the Trust has focused on three core areas for reinvestment aimed at organic growth: North East British Columbia, Central Alberta and Oklahoma. In 2006, 45 gross wells (13.1 net wells) were drilled in these core areas with a 100% success rate. While the majority of these wells were drilled with no capital investment by the Trust, it is the new strategic direction of Enterra to finance and operate a substantial portion of its future exploitation effort in its core areas. These programs are described in the sections that follow.

NORTH EAST BRITISH COLUMBIA

At year end 2006, the Trust produced 7.9 mmcf/day of sweet, dry gas at Desan in the Greater Sierra Area, 120 kilometers northeast of Fort Nelson, British Columbia. Production is derived from the Jean Marie formation at a depth of approximately 1,300 meters (4,250 ft.), from horizontal wells which are drilled using underbalanced drilling fluid technologies. These wells provide very good initial production followed by a period of slow, predictable decline ideally suited to a long term stable enterprise.

The Jean Marie carbonate/shale gas play has been and is being exploited by various competitors including some of the largest oil and gas companies in Canada. Success requires a geophysical and geological understanding of the play, coupled with effective program execution. While it is extensive and broad in nature, finding the productive portions of the Jean Marie reservoir starts with skilled geophysical interpretation. Horizontal wells are then located to access prospective reservoir rock which contains sufficient permeability to effectively drain the hydrocarbons.



The drilling season in North East B.C. is short as most areas are accessible only during frozen winter conditions. Acquiring services and planning logistics begins in early summer in careful preparation for the intense level of activity in the months to come. An added level of complexity to the drilling operation is the need to keep fluids from invading the reservoir during the drilling process. To accomplish this, underbalanced techniques are employed which require additional services and personnel. The Trust employs a team fully capable of bringing this opportunity to fruition.

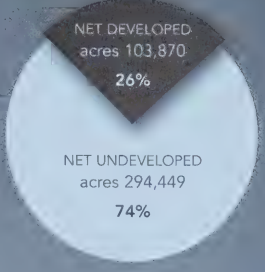
In the process of testing the Jean Marie play, the Trust drilled one well and completed a 3D seismic program on our offsetting acreage. We are planning to drill two additional wells during the summer months of 2007 using the new seismic survey to position these holes for optimum results. A significantly larger program is planned for the winter drilling season of 2007/2008. This stepped approach to development of the area is typical of the systematic methodology our team will use to successfully manage risk and develop long life assets for the Trust.




Desan
Peggo
Pesh
Kotcho
Clair
Ferrier
Ricinus
Sylvan
Wainwright
Alliance
Provost
Princess
Powder River Basin
Rocky Mountain Gas, Inc.
WYOMING
K-9 Area
Carney
Altex Energy
Central Area

	CANADA	US	TOTAL
DEVELOPED ACRES			
Gross	156,216	38,339	194,555
Net	75,740	28,130	103,870
UNDEVELOPED ACRES			
Gross	205,552	246,218	451,770
Net	142,681	151,768	294,449
Total acres			
Gross	361,769	284,557	646,326
Net	218,421	179,898	398,319

LAND HOLDINGS
(at December 31, 2006)







CENTRAL ALBERTA

West Central Alberta

In West Central Alberta, the Trust has gas producing properties in the foothills of Alberta at Ricinus, Ferrier, and Lochend, and an oil property at Sylvan Lake. The Cardium trends through these fields are attractive and active areas for the energy sector to pursue due to longer reserve life, low operating costs, and high value natural gas liquids and condensate associated with the gas production. The Trust produced 2,220 boe/day from this area at the end of 2006.

At Ricinus, the Trust is a 50% owner of a prolific, deep Leduc well operated by an experienced partner with significant sour gas experience. This well has flowed consistently at gross rates up to 9 mmcf/day since coming on production in the fall of 2006. Enterra and its partner are currently evaluating a potential follow-up location.

Further north in western Alberta, the Trust operates a light oil field at Clair on the Peace River Arch. This property has the distinction of being among the lowest operating cost properties within our portfolio, and is presently under water flood to maximize ultimate oil recovery. Production at the end of 2006 at Clair was 1,320 boe/day.

While relatively mature in nature, these areas possess a range of additional drilling opportunities that the Trust is currently reviewing. We have over 30,000 net acres of undeveloped land currently available in West Central Alberta.



East Central Alberta

Enterra operates a number of mature light to medium gravity oil fields with associated natural gas in eastern Alberta. These properties span from Provost, Wainwright, and Alliance in the north to Princess in the south. This area is characterized as having established and predictable production profiles. In aggregate, these fields produced 2,330 boe/day at the end of 2006.

While these fields are relatively mature, our development team continues to find opportunities. For example, in early in 2007 we drilled a new well in the Halkirk area to extend an oil pool onto our lands. Completions are currently underway and several follow-up locations are potentially planned for 2007.





WYOMING

Powder River Basin

While the minor production currently generated from our coal bed methane project is not material to our overall portfolio (approximately 200 boe/day at the end of 2006), there is significant long term potential in the pursuit of new untested coals on our lands. In late 2005 and early 2006, over 40 wells were drilled on these lands including two dewatering pods. The performance for these pods has been positive to date with good flow of water, an important factor in this type of coal bed methane prospect. We hope that these coals will break to flow commercial natural gas in 2007 and provide for a solid follow-up development program. Also, at our Oyster Ridge prospect, it is our intent to establish a third test pod and begin dewatering in late 2007.

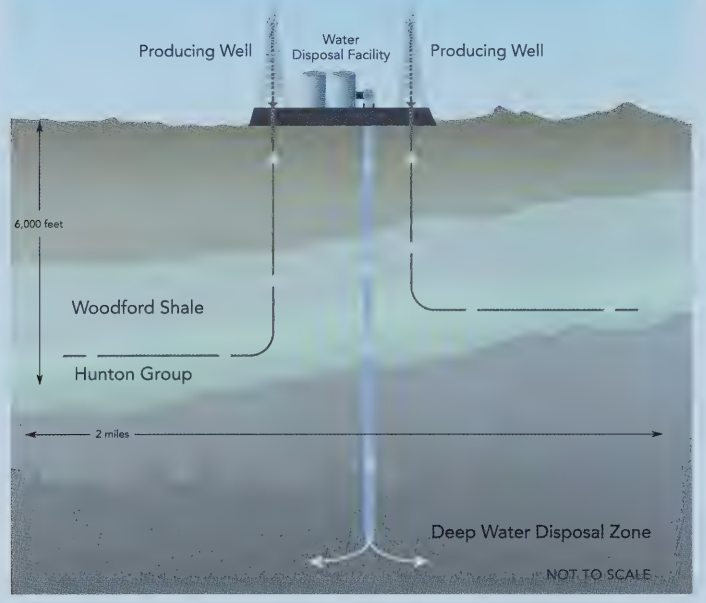


OKLAHOMA

In 2006, Enterra acquired assets located in the Central and North Central portions of the State of Oklahoma. The majority of the production from these assets is from the Hunton formation, a Silurian/ Devonian carbonate reservoir. Dewatering is the primary method of production. The process requires the removal of large volumes of water to decrease reservoir pressure and allow entrained hydrocarbons to be liberated from the reservoir.

Original field development was done by drilling close-spaced vertical wells. Such a program could result in as many as 8 to 16 wells per section (1 section = 640 acres). Studies of logs and cores early in the life of the project led to drilling of the first horizontal Hunton well in late 2000. Based on the results of that test, the method of developing the Hunton reservoir was changed from vertical drilling to horizontal drilling.





Schematic illustration showing multi-well drilling pad with water disposal scheme.

Recent development has incorporated the drilling of horizontal wells with one to three open hole laterals ("crow's foot" drilling). Current spacing is one well per section using one of the various horizontal designs. This drilling program lends itself to the use of multi-well drilling locations. A single site can contain up to 4 producing wells and a saltwater disposal well with a distance of 35 feet to 50 feet between the wellheads and a tank battery complex that houses all the facilities for each of the wells on that site. This strategy minimizes costs and reduces environmental impact.

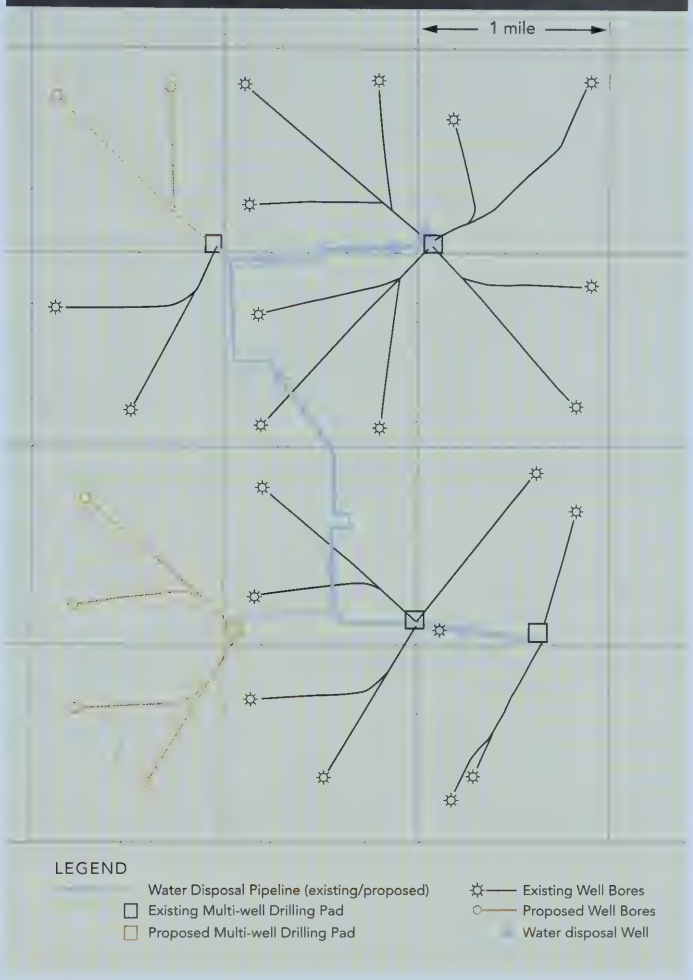
In 2006, Enterra's strategic partner Petroflow Energy drilled 12 horizontal wells on the Trust's lands under the terms of a farmout agreement where Petroflow pays 100% of drilling costs and the Trust retains 30% of the new production and reserves.

K-9 Project Area

The K-9 Project is located in Grant and Garfield Counties in North Central Oklahoma. Enterra's assets in this project include extensive undeveloped lands and working interests in 18 producing wells, two saltwater disposal wells and extensive gathering infrastructure.

At K-9, the Hunton formation depth is approximately 6,300 feet. Current production is from a combination of high angle directional wells and short single lateral horizontal wells. Production is primarily rich gas with some 45° API crude oil. The 2006 exit volumes from this project were 7.7 mmcf/day of natural gas and 10 bbls/day of oil.

As of year end, nine producing wells were drilled and one saltwater disposal well was completed. Most of the wells are in the early stages of dewatering, and results are being evaluated with



Example layout of multi-well pads and water disposal system.

many wells still showing inclining hydrocarbon production rates. The projection for drilling in this field in 2007 is to have 6 to 8 additional wells on production prior to the end of the year.

Central Project Area

The Central project area is located in Lincoln County, Oklahoma. The original phase of development has proven to be a very successful play. The reservoir rock is predominantly a tight dolomitic limestone. Early tests from vertical wells drilled in this field indicated good reservoir porosity with low permeability. Subsequent horizontal drilling has enabled the company to decrease well density and costs, and increase well productivity.

The first producing well drilled by Petroflow in January of this year has exhibited excellent production rates to date. The 2007 drilling program is intended to be very concentrated in this area with 12 to 16 wells planned. Trust exit volumes for 2006 from the area were 5.6 mmcf/day of natural gas and 407 bbl of 44° API crude oil per day.

BUSINESS ENVIRONMENT

Commodity Prices

North America saw a tremendous swing in oil and gas pricing during 2006. Nymex natural gas prices averaged a high of US$11.43/mmbtu in January and dove to a low of US$4.20 in October, a decline of 63%. West Texas Intermediate crude oil fluctuated from US$74.41/bbl in July and fell to US$58.83 in October, a decline of 21%. For the year, these benchmark prices averaged US$7.23/mmbtu for natural gas and US$66.09/bbl for oil, a drop of 16% and a rise of 17% respectively over 2005.

It is clear that hurricanes had a tremendous influence on natural gas prices in late 2005 and early 2006. However, generally milder weather in 2006 allowed natural gas storage to rise to record levels, putting downward pressure on prices. Many large exploration and production companies chose to curtail their spending on natural gas programs in late 2006 in light of lower prices and increasing industry costs. Experts are concerned that the reduction in drilling may seriously impact the ability of the industry to meet consumer needs in late 2007.

Oil prices have been heavily influenced by an uncertain geo-political environment. Any perceived threats to supply have had a dramatic impact on near term pricing. Forward prices for the sale of crude oil are indicating that no significant downturn in prices is likely in 2007 and beyond.

Enterra mitigates the risk of commodity price fluctuations with an active price hedging program more fully described in the Management's Discussion and Analysis portion of our Financial Report. Costless collars are used which provide floor prices and also provide a range of participation in price upside. In 2006 this program was very effective at lessening the impact of sudden downturns in prices and contributed approximately $12 million in revenue to the Trust.

Services

Industry sources have reported that service sector costs increased between 30% and 50% during the course of 2006. These higher costs have had a direct impact on the Trust's bottom line. To address this pressure, Enterra embarked on a concerted effort to lower its operating costs. Overall operating cost per unit dropped 3% from $11.55/boe to $11.17/boe. This was achieved through a focus on lower cost gas assets, divestiture of some higher cost oil assets, deferred spending programs and term purchase contracts for electricity at lower rates. In 2007 it appears that service costs will soften somewhat and Enterra continues to carefully manage this area of its business.

Competitor Performance

In mid-2005 it was clear that Enterra's portfolio of assets and operations was lagging that of our peers. We set goals for improvement in 2006, including the balancing of our oil/gas ratio and reduction of our cost structure. Our production mix is now 38% oil and 62% gas, which leaves us poised to take advantage of both commodity markets. In 2006 the Trust made progress in other areas including unit operating costs (-3%), and finding, development and acquisition costs (-17%). These successes have improved our position against our competitors, many of whom saw performance declines in 2006. For 2007 our efforts to improve are priority goals for the organization and all employees.

HEALTH, SAFETY & ENVIRONMENT



An important mandate of the Trust is to safeguard the health and safety of our employees and contractors, and to protect and preserve the environment associated with our operations. In early 2006 we established a full-time Health, Safety and Environment ("HSE") Coordinator who was tasked with building and rolling out a variety of programs, policies and procedures to ensure that we have industry's best practices in place. Some of these initiatives include HSE manuals, pressure vessel inspection programs, electrical maintenance and inspection standards, emergency response testing and comprehensive training for field personnel. Enterra is committed to developing a culture of personal accountability for safety and protecting the environment on behalf of an array of stakeholders: employees, contractors, neighbours and regulators.

Community Involvement

Enterra employees are actively involved in the communities in which we work. In 2006 the Trust provided financial support for various organizations and causes including sports teams, music festivals, the 4H Agricultural Club, and an industry museum. We also encourage and support our employees in their commitment of time and effort to charitable causes. This program is overseen by a donations committee consisting of employees from across the company.

CORPORATE GOVERNANCE



Enterra Energy's management team and Board of Directors believe that a firm commitment to the highest standards of corporate governance is essential for the ongoing success of the Trust.

Our corporate governance practices are compliant with National Policy 58-201 and with the guidelines of the Canadian Securities Administrators. Our Board of Directors supervises and evaluates the management of the Trust and oversees matters related to our strategic direction, business, and operations. The Board's mission is to protect and represent the interests of unitholders.

At present the Board of Directors has established five committees to reflect best practices in disclosure and governance: an Audit Committee, a Compensation Committee, a Reserves Committee, a Health, Safety, Environment and Regulatory Compliance Committee and a Governance and Nominating Committee.

For a complete review of our corporate governance practices, please refer to our Management Information Circular, available on SEDAR at www.sedar.com.

The Board of Directors

R. H. (Joseph) Vidal, Chairman
President & Chief Executive Officer of Bioriginal Food & Science Corp.

Peter Carpenter, Director
Senior Partner (Oil and Gas) and Director of financial advisory firm Claridge House Partners, Inc.

Roger Giovanetto, Director
President of R&H Engineering, Ltd.

W. Cobb (Chip) Hazelrig, Director
President of The Hazelrig Companies, Inc.

Norman W.G. Wallace, Director
Owner of Wallace Construction Specialties Ltd.

E. Keith Conrad,
President & CEO and Director

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Stock Exchange Listings

NYSE (symbol: ENT)
TSX (symbol: ENT.UN)

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Peter Carpenter
Roger Giovanetto
W. Cobb (Chip) Hazelrig
Norman W.G. Wallace
E. Keith Conrad

Senior Management

E. Keith Conrad,
President & Chief Executive Officer

Victor Roskey,
Senior Vice President & Chief Financial Officer

John F. Reader,
Senior Vice President Corporate Development

James (Jim) Tyndall,
Senior Vice President Operations &
Chief Operating Officer

Kim Booth,
Vice President & Chief Operating Officer,
U.S. Operations

Investor Relations Website

www.enterraenergy.com

Annual General and Special Meeting

June 14, 2007, 10 a.m. MT
Metropolitan Centre
Grand Lecture Theatre
333 – 4th Avenue S.W.
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